

Energy Market Transparency: Analyzing the Impacts of Constraint Relaxation and
Out-of-Market Correction Practices in Electric Energy Markets

by

Yousef Mohammad Al-Abdullah

A Dissertation Presented in Partial Fulfillment
of the Requirements for the Degree
Doctor of Philosophy

Approved March 2016 by the
Graduate Supervisory Committee:

Kory Hedman, Chair
Vijay Vittal
Lalitha Sankar
Gerald Heydt

ARIZONA STATE UNIVERSITY

May 2016

ABSTRACT

This work presents research on practices in the day-ahead electric energy market, including replication practices and reliability coordinators used by some market operators to demonstrate the impact these practices have on market outcomes. The practice of *constraint relaxations* similar to those an Independent System Operator (ISO) might perform in day-ahead market models is implemented. The benefits of these practices are well understood by the industry; however, the implications these practices have on market outcomes and system security have not been thoroughly investigated. By solving a day-ahead market model with and without select constraint relaxations and comparing the resulting market outcomes and possible effects on system security, the effect of these constraint relaxation practices is demonstrated.

Proposed market solutions are often infeasible because constraint relaxation practices and approximations that are incorporated into market models. Therefore, the dispatch solution must be corrected to ensure its feasibility. The practice of correcting the proposed dispatch solution after the market is solved is known as *out-of-market corrections (OMCs)*, defined as any action an operator takes that modifies a proposed day-ahead dispatch solution to ensure operating and reliability requirements. The way in which OMCs affect market outcomes is illustrated through the use of different corrective procedures. The objective of the work presented is to demonstrate the implications of these industry practices and assess the impact these practices have on market outcomes.

DEDICATION

To

my father, Mohammad Yousef Al-Abdullah, and my mother, Rita Catherine Al-Abdullah

ACKNOWLEDGMENTS

A special acknowledgement must be given in recognition of the advice and mentoring of Dr. Kory Hedman (Assistant Professor, School of Electrical, Computer, and Energy Engineering) and Dr. Vijay Vittal (Professor, School of Electrical, Computer, and Energy Engineering), without whom this work would not be possible. The author also thanks the Director General of Kuwait Institute for Scientific Research (KISR), Dr. Naji Al-Mutairi, and former President of Kuwait University, Dr. Abdullatif Al-Bader, for their encouragement, and the Power Systems Engineering Research Center (PSERC) for its support and financial contribution to this endeavor. The author would also like to acknowledge fellow Ph.D. students Ahmed Salloum and Mojdeh Abdi-Khorsand, who contributed to the work on Constraint Relaxation practices and Out-of-Market Corrections, respectively. Finally, the author would like to acknowledge Mr. Adnan Al-Fulaij and Mr. Del Hindle for their guidance.

TABLE OF CONTENTS

	Page
LIST OF TABLES	viii
LIST OF FIGURES	ix
NOMENCLATURE	x
CHAPTER	
1. INTRODUCTION	1
1.1 Statement of Research Area	1
1.2 Literature Survey: Constraint Relaxations	2
1.3 Literature Survey: Out-of-Market Corrections	6
1.4 Report Organization	8
2. BACKGROUND	10
2.1 Introduction	10
2.2 Optimal Power Flow	10
2.3 Security Constrained Unit Commitment Model	13
2.4 Example of the Impact Constraint Relaxations have on the Dual Variable	17
2.5 Contingency Analysis	20
2.6 Extensive-Form Stochastic Unit Commitment	23
2.7 Summary	27
3. INDUSTRY REVIEW OF CONSTRAINT RELAXATION PRACTICES	28

CHAPTER	Page
3.1 Introduction	28
3.2 Day-Ahead Scheduling Process	29
3.3 California Independent System Operator (CAISO)	34
3.4 Midcontinent Independent System Operator (MISO)	35
3.5 Electric Reliability Council of Texas (ERCOT)	36
3.6 New York Independent System Operator (NYISO)	37
3.7 Independent System Operator of New England (ISO-NE)	38
3.8 Pennsylvania Jersey Maryland Interconnection (PJM)	38
3.9 Summary	39
4. EFFECT OF CONSTRAINT RELAXATION PRACTICES ON MARKET OUTCOMES.....	40
4.1 Introduction	40
4.2 Security Constrained Unit Commitment with Key Constraint Relaxations.....	41
4.3 RTS-96 Test Case.....	43
4.4 PJM Test Case	44
4.5 Correction Process to Attain AC and N-1 Feasibility	45
4.6 Market Implications	46
4.6.1 RTS-96 Test Case Results	46
4.6.2 PJM Test Case Results	51

CHAPTER	Page
4.6.3 Discussion	57
4.7 Conclusions	58
5. EFFECT OF RESERVE RELAXATIONS ON <i>N</i> -1 SECURTY	60
5.1 Introduction	60
5.2 Procedure.....	61
5.2.1 SCUC without Reserve Relaxations	62
5.2.2 SCUC Reformulation to Include Reserve Relaxations.....	64
5.3 Contingency Analysis with Acquired Reserves	66
5.4 Benders' Decomposition	67
5.5 Results	68
5.6 Conclusions	73
6. OUT-OF-MARKET CORRECTIONS	75
6.1 Introduction	75
6.2 Industry Practices	77
6.2.1 AC Feasibility	77
6.2.2 Representation of the Network Model	78
6.2.3 Reserve Requirements	78
6.2.4 CAISO's Integrated Forward Market	79
6.3 Problem Formulation.....	80

CHAPTER	Page
6.3.1 Day-Ahead Security Constrained Unit Commitment	82
6.3.2 Contingency Analysis	83
6.4 Out-of-Market Correction Procedures	84
6.4.1 OMC procedure 1	84
6.4.2 OMC procedure 2	86
6.4.3 Ranking with the PTDF Heuristic	87
6.4.4 Ranking with the Greedy Algorithm.....	88
6.5 Results and Analysis	90
6.6 Conclusions	98
7. CONCLUSIONS AND FUTURE WORK	100
7.1 Conclusions	100
7.2 Future Work	104
REFERENCES	106
APPENDIX	
A. CONSTRAINT RELAXATION MODEL AMPL MODEL AND RUN FILES	113
B. CONTINGENCY ANALYSIS FROM TRANSMISSION CONTINGENCIES	122
C. GREEDY ALGORITHM FOR TRANSMISSION CONTINGENCIES	124
D. CALCULATION OF UPLIFT PAYMENTS WITH OPPORTUNITY COSTS	126

LIST OF TABLES

Table	Page
4.1. Relaxed Transmission Line Limits Produced by SCUC-CR.....	47
4.2. Market Results in (\$k for tested peak day) for SCUC-CR and SCUC.	50
4.3. Market Results for PJM Market and Resulting <i>N</i> -1 Final Feasible Solutions (\$k per hour tested).....	56
5.1. Spinning Reserve Relaxation Prices.	66
5.2. Non-Spinning Reserve Relaxation Prices.	66
5.3. Reserve Relaxations Distinguished by Penalty Scheme and Reserve Type (MW)... ..	70
5.4. Total System Cost Summed Over Days with Relaxations (\$k) for Initial Market Solutions for Relaxed and Non-Relaxed Cases and Time Period with Relaxations for Relaxed Cases (days).	70
5.5. Total <i>N</i> -1 Violations for hours with Relaxations (MW).....	71
5.6. <i>N</i> -1 Secure Solutions' Total System Costs Summed Over Days with Relaxations in (\$k) and Time Period (days).	72
6.1. Market Settlements for Extensive-form SCUC and SCUC (\$k for Test Day).	92
6.2. Total Costs and Market Settlements of OMCs (\$k for Test Day).	93
6.3. Dispatch Difference Between SCUC, Greedy, PTDF, Greedy-A, and ESCUC-UC.	97

LIST OF FIGURES

Figure	Page
1.1 Proposed Staircase Penalty Price Function by ERCOT [5].	5
1.2 MISO Day-Ahead Market Process [16].	8
2.1. The Π -Equivalent Circuit of a Transmission Line.	11
2.2. LP Example to Demonstrate the Effects of Constraint Relaxations on Dual.	18
2.3. Graphical Interpretation of Relaxing a Constraint.	19
2.4. Transmission Line Ratings Where Rate C is the Short Term Emergency Rating, Rate B is the Long Term, and Rate A is the Rating During Normal Operating States, i.e., No Contingency Present.	21
3.1. General Day-Ahead to Real-Time Market Process Adapted from ERCOT [32].	32
3.2. Modified Day-Ahead Market Process for MISO [16].	33
4.1. Two Stage Process to Achieve AC and $N-1$ Feasible Dispatch Solution.	41
4.2. System Settlement Results for Both On- and Off-Peak Hours, with and without Relaxations; Generator Revenue, Generator Profit, and Load Payment Include the Uplift Payments.	57
6.1. Day-Ahead Scheduling Process with OMCs.	81
6.2. Detailed Process Employed by Both OMC Procedures.	86
6.3. System Settlements for the Different Unit Commitment Solutions and with Different Settlement Policies by Using SCUC LMPs Versus OMC LMPs.	96
6.4. LMPs Averaged Over All Hours at Major Generator Buses.	98

NOMENCLATURE

AC	Alternating current
ACOPF	Alternating current optimal power flow
B_k	Parameter for transmission line susceptance
c	Parameter for indexing contingencies
C	Parameter for the set of contingencies in the test case
CAISO	California Independent System Operator
c_g^{NL}	No load generator cost
c^{NS}, c_x^{NS}	Penalty price for non-spinning reserve; fixed-price and staircase-price relaxations.
c_g^{op}	Linear operating cost
c_{gi}^{op}	Piecewise/segmented
c_g^{SD}	Generator shutdown cost
c_g^{SU}	Generator startup cost
c^{SP}, c_x^{SP}	Penalty price for spinning reserve; fixed-price and staircase-price relaxations.
DAM	Day-ahead market
DCOPF	Direct current optimal power flow
DDP	Desired dispatch point
d_{nt}	Parameter for the demand/load at node n during time period t
DT_g	Parameter for the minimum down time requirement for generator g
EMS	Energy management system

ERCOT	Electric reliability council of Texas
ESCUC	Extensive-form stochastic security constrained unit commitment
e	Parameter used to index element e removed in ESCUC model
E	Parameter for the set elements (generator or non-radial transmission) in the test case in ESCUC model
FMP	Flowgate marginal price
FS_g	Parameter to indicate fast start generators $FS_g = 1$ for fast-start generators and 0 otherwise
g	Parameter for indexing generators
G	Parameter for the set of generators in the test case
$g(n)$	Parameter for indexing generators for generators g at node n
$H(g)$	Parameter for indexing hydro-electric generators
i	Parameter for indexing generator cost segments
I	Parameter for the set of generator cost segments in the test case
IEEE-118	Institute of Electrical and Electronics Engineers 118 bus test case
IFM	Integrated Forward Market (CAISO)
IPP	Independent Power Producer
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
j	Parameter for indexing penalty price segments (SCUC-SP)
J	Parameter for set penalty price segments (SCUC-SP)
k	Parameter for indexing transmission assets
K	Parameter for the set of transmission assets in the test case

$LODF_{kz}$	Line outage distribution factor for flow on line k with the loss of line z .
LP	Linear program
LMP	Locational Marginal Price
LSE	Load Serving Entity
m	Parameter to indicate from bus
MMS	Market Management System
MISO	Midcontinent Independent System Operator
MVL	Marginal value limit
n	Parameter for indexing nodes/buses
N	Parameter for the set of nodes/buses in the test case
$N1_{ec}$	Parameter used to indicate the element e removed for contingency c for the ESCUC model
$N1_g$	Parameter for indicating a single generator contingency ($N1_g = 0$) otherwise 1 in the contingency analysis tool and greedy algorithm
$N1_k$	Parameter for indicating a single non-radial transmission contingency ($N1_g = 0$) otherwise 1 in the contingency analysis tool and greedy algorithm
NP	Parameter for number of periods in the test case
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
OMCs	Out-of-market corrections
OPF	Optimal power flow

P_g^{max}	Parameter for generator g maximum supply output
P_g^{min}	Parameter for generator g minimum supply output
P_{g0t}, P_{gct}	Variable for generator g supply output for contingency c ($c = 0$ is base case where no contingency is present) for time period t
P_{git}^{seg}	Variable for generator g supply output for segment i for time period t
P_{gi}^{Limit}	Parameter for generator g supply limit output for segment i
P_{gt}^{total}	Variable for total generator g supply output for time period t
P_{gt}	Variable for generator g supply output for time period t
\bar{P}_{gt}	Parameter for to indicate the supply output for generator g for time period t
\hat{P}_{gt}	Variable for generator g for time period t for the new supply output
P_k^{max}	Parameter for branch k maximum flow limit, normal rating
$P_k^{max,c}$	Parameter for branch k maximum flow limit, emergency rating
P_{kt}	Variable for power flow through branch k for time period t
P_{nct}^{inj}	Variable for net power injection from bus n during time period t when contingency c is present
P_{nt}^{inj}	Variable for net power injection from bus n during time period t
PJM	Pennsylvania Jersey Maryland Interconnection
PSCOPF	Preventive Security Constrained Optimal Power Flow tool PSS/E
PSS/E	Power System Simulator for Engineering (Siemens)

PTDF	Power transfer distribution factor
$PTDF_{k,n}^{REF}$	Power transfer distribution factor for delivering power from bus n to REF bus on branch k
$PTDF_{nkc}^{REF}$	Power transfer distribution factor for delivering power from bus n to REF bus on branch k when contingency c is present
Q_k	Reactive power flow
q_n	Reactive power demand
R_g^{10}	Emergency ramp rate for generator g
R_g^{HR}	Hourly ramp rate for generator g
R_g^{SU}, R_g^{SD}	Max startup and shutdown ramp rates of unit g .
$\overline{R_{gt}^{SP}}, \overline{R_{gt}^{NS}}$	Scheduled operating reserve for unit g in period t . For contingency analysis with acquired reserves.
r_{gt}^{NS}	Acquired non-spinning reserve for generator g during time period t
r_{gt}^{SP}	Acquired spinning reserve for generator g during time period t
r_t^{total}	Acquired total system reserve during time period t
RCP	Reserve clearing price
RTO	Regional Transmission Organization
RTS-96	Reliability Test System 1996 version
RUC	Reliability (or residual) unit commitment

s_{kt}^+	Variable for violation on the positive limit of transmission asset k during time period t when a contingency is present in the contingency analysis tool and greedy algorithm
s_{kt}^-	Variable for violation on the negative limit of transmission asset k during time period t when a contingency is present in the contingency analysis tool and greedy algorithm
s_t^{NS}, s_{tx}^{NS}	Variable for violating non-spinning reserve requirement during time period t – fixed-price and staircase price
s_t^{SP}, s_{tx}^{SP}	Variable for violating spinning reserve requirement during time period t – fixed-price and staircase
SCED	Security constrained economic dispatch
SCUC	Security constrained unit commitment
SCUC-CR	Security Constrained Unit Commitment with constraint relaxations
SPP	Southwest Power Pool
t	Parameter used to index time periods
T	Parameter for the set of time periods in the test case
u_{gt}	Variable for status of generator g during time period t
\bar{u}_{gt}	Parameter used to input status of generator g during time period t
\hat{u}_{gt}	Variable for new status of generator g during time period t
UT_g	Parameter for the minimum up time requirement for generator g
v_{gt}	Variable to startup of generator g during time period t
WECC	Western Electricity Coordinating Council

w_{gt}	Variable to shutdown of generator g during time period t
x	Parameter for indexing staircase prices and capacities.
X	Parameter for set of staircase prices and capacities.
z	Parameter for indexing lost line in LODF formulation.
Z	Parameter for set of lost line in LODF formulation.
α_{nt}^c	Parameter used to rank nodes with the PTDF heuristic at node n during time period t for contingency c
β_{kt}^c	Parameter used to decide needed line flow direction with the PTDF heuristic at node n during time period t for contingency c
γ_{cg}^{status}	Parameter used to rank committing additional generator g with the PTDF heuristic for contingency c
γ_{cg}^{DDP}	Parameter used to rank modifying the supply output generator g with the PTDF heuristic for contingency c
$\delta^+(n)$	Parameter for the set of transmission lines with power flowing into bus n
$\delta^-(n)$	Parameter for the set of transmission lines with power flowing out of bus n
δ_{gt}	Variable used as the re-dispatch indicator variable for unit g in period t for the greedy algorithm
θ_{nt}	Voltage angle at bus n during time period t
λ_{DDP}	Dual variable of constraint on generator g for modifying DDP
λ_{status}	Dual variable of constraint on unit g for modifying status

λ_{kt}^{FMP}	Flowgate marginal price of line k in period t
λ_{nt}^{LMP}	Locational marginal price at bus n in period t
λ_t^{RCP}	Reserve clearing price in period t
ρ_{cg}^{DDP}	Estimated benefit to change DDP of unit g to reduce violations of contingency c for the greedy algorithm
ρ_{cg}^{status}	Estimated benefit to commit unit g to reduce violations of contingency c for the greedy algorithm

1. INTRODUCTION

1.1 Statement of Research Area

The electric power industry is challenged by the task of ensuring a reliable and continuous supply of electric energy, which, unlike other consumable goods, must be generated, delivered, and consumed simultaneously. Market operators are required to manage their generation fleet constrained by complex operating requirements while maintaining synchronism and managing thousands of miles of transmission assets. Operators must also follow strict federal and regional reliability standards, cope with demand, and more recently, generation uncertainty, all while having limited economical energy storage capability. Due to the complexity of these requirements, the industry approximates these requirements, particularly when operators are solving their deterministic unit commitment models.

In addition to approximation, the unit commitment models currently employed by operators also have their requirements relaxed in order to ensure that operators obtain a solution. The proposed solution, with the resulting relaxations and approximations, may be modified because it is likely to be infeasible for not satisfying some particular requirement. The modifications that occur outside of the market (hence the term, “out-of-market correction”), are due to relaxations and approximations that affect the outcomes of the markets, of concern to market participants who perceive these modifications as biased interventions by operators. However, these modifications are necessary because, again, the proposed solution was truly infeasible.

The industry seeks to understand the effect constraint relaxation and out-of-market correction practices have on market outcomes, which the work presented in this report and yet to be conducted seeks to characterize. To gain a better understanding, a survey of constraint relaxation and out-of-market corrections as practiced by different system operators was conducted. Constraint relaxation practices deemed critical were replicated in a day-ahead market model. This market model was solved with and without the constraint relaxation practices and the resulting market outcomes were compared. Different corrective procedures for out-of-market correction practices were developed and tested against a standard reliability requirement criterion, known as $N-1$ reliability, where the removal of one critical element in the system does not cause violations. After $N-1$ reliability was achieved, the procedures were compared to the market before and after the modifications were made to demonstrate their effect on market outcomes.

1.2 Literature Survey: Constraint Relaxations

Several ISOs and RTOs utilize constraint relaxations in their market model, including CAISO, ERCOT, and SPP [1]-[6]. This practice is implemented by including slack variables in constraints that the ISO chooses to have relaxed. The ISO then discourages the market model from readily choosing to relax constraints by forcing the model to pay a penalty price for the relaxations present in the solution. The penalty price is a pre-determined parameter set by the ISO and is typically negotiated with market participants. By allowing certain constraints to be violated for a set penalty price, the market model still imposes the constraint, but not as a “hard” constraint, which could otherwise cause the market model to be infeasible and result in no solution returned. By incorporating

these as “soft” constraints, operators are ensured a solution is obtained from the day-ahead security constrained unit commitment (SCUC) market model. Furthermore, the approximations incorporated in these market models could limit the model from finding a feasible solution. Therefore, it is argued that these constraints should be modeled as soft constraints, which may be violated for a set penalty price, instead of hard constraints that must always be satisfied. Another benefit enjoyed by operators from these constraint relaxation practices is price control. The penalty price acts as a bid cap to the constraint of the slack variable to which it was added.

There has been some investigation into constraint relaxation practices. In [7] and [8], new pricing mechanisms for penalty factors are proposed similar to the one proposed by ERCOT. Both reports propose a “multi-step” penalty price function in place of the fixed-price penalty prices used today. For example, [7] in particular scrutinizes transmission constraint pricing, because it affects the Locational Marginal Prices (LMPs), a market clearing mechanism used at a particular location in the network to determine the amount paid generators for their energy production or to charge customers for their consumption. In [8], simulations were performed to assess the effects of different penalty pricing structures on Southwest Power Pool’s (SPP) Security Constrained Economic Dispatch (SCED) model.

Penalty prices are agreed upon by the ISO along with their stakeholders and are approved by the utility commission. At CAISO, operators separate the day-ahead market, also known as the Integrated Forward Market (IFM), into a “Scheduling Run” and a “Pricing Run” [9]. The scheduling run has higher penalty prices and prioritizes the enforcement of some constraints over others. For example, CAISO’s scheduling run has a

\$6500/MWh penalty price for violating the market energy balance constraint, which is prioritized higher than the ancillary service non-spin requirement because it only has a penalty price of \$2250/MWh [1]. When solved, the scheduling run determines the dispatch solution for the forward, day-ahead, market. The scheduling run's solution may have relaxed some constraints. It is fed into the pricing run, which has lower penalty prices, where CAISO determines settlements for the IFM. The pricing run solution is not allowed to deviate significantly from the scheduling run solution [10] because the pricing run determines the settlement policy for the generators that were awarded dispatches in the scheduling run. This separation changes the resulting prices, i.e. the LMPs. In particular, the scheduling run at CAISO had a \$6500/MWh penalty price on energy balance constraints, whereas in the pricing run, the system only pays \$500/MWh. As a result, for a node that had a constraint relaxation, i.e. the slack variable was greater than zero, the LMP is restricted to \$500. Thus if a generator is located at that bus, that particular generator would not receive a higher profit. At CAISO, these constraint relaxation practices also extend to other areas in the market, such as in their Residual Unit Commitment (RUC), also known as a reliability unit commitment, and in the Real-Time Market (RTM).

ERCOT follows similar procedures in their Day-Ahead Market (DAM) and lists their penalty prices, which they call penalty factors in [5]. ERCOT also proposes using a staircase penalty cost function in its DAM, represented in Figure 1.1. ERCOT currently still appears to use a single penalty price of \$5,000,000/MWh for the under/over generation constraint [5].

The Southwest Power Pool (SPP) also appears to follow the same practice in its day-ahead market, or in its terminology, the DA Market. SPP states that it allows for “Violation Relaxation Limits” to occur when a feasible solution cannot be obtained when trying to enforce all constraints. This is listed along with their penalty prices in [2]. For example, SPP has a “Global Power Balance” constraint whose penalty price is set to \$50,000.

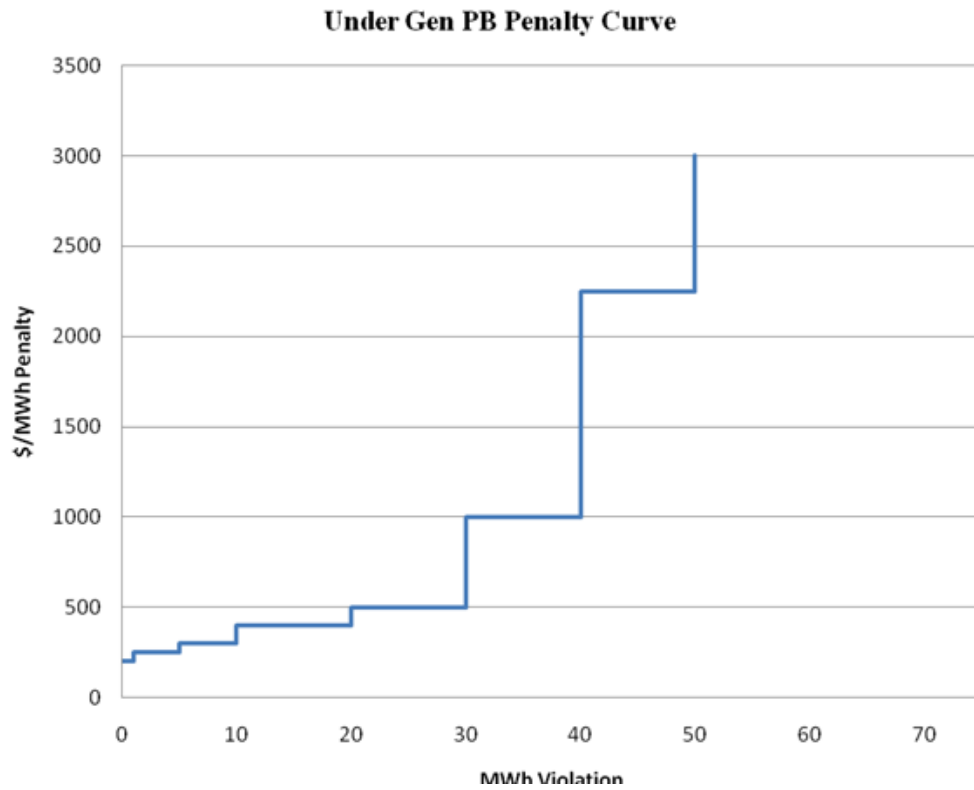


Figure 1.1 Proposed Staircase Penalty Price Function by ERCOT [5].

Currently, what is understood from industry is that ISOs and RTOs apply constraint relaxations practices in a similar manner. Choosing select constraints to relax, the ISO or RTO will add slack variables to the constraints and associate a penalty price to these slack variables in the objective function. ISOs and RTOs begin to differ on which constraints to relax, the penalty price values, and the structure of these penalty prices. In

this chapter, only some of the constraint relaxation practices that ISOs and RTOs incorporate into their market models were considered for evaluation. Further investigation into other ISOs has been documented in Chapter 3.

1.3 Literature Survey: Out-of-Market Corrections

To solve the complex problem of dispatching energy efficiently at the day-ahead time stage, a SCUC model is solved with various approximations for all the relevant operating constraints. Due to inaccuracies in the day-ahead market process, corrections will eventually need to be made. These corrections, known as Out-of-Market Corrections (OMCs), are any modifications made to the market solution when it does not satisfy operational and reliability requirements. OMCs are employed by all system operators, regardless whether the organization is an Independent System Operator (ISO) or a vertically integrated utility. For example, some market models ignore power transfer distribution factors (PTDFs) below a certain threshold [1]. These small PTDFs affect the flow of power on transmission assets; however, they remain unaccounted for, which can lead to an infeasible operating state, thereby requiring a correction to the market solution. Applying OMCs after the market solution has been posted is one method of performing these corrections.

OMCs can be performed in a more formalized manner. The day-ahead scheduling process occurs in multiple stages. The system operator first solves a unit commitment formulation that includes all market participants and after approving the dispatch solution, the operator solves a reliability unit commitment (RUC) model [11]. The RUC itself could also be solved in multiple stages, such as using a scheduling and pricing run [9].

Within the RUC, the operator seeks to acquire more capacity to ensure it can satisfy forecasted demand for the next operating day, which may not have been acquired by market participants and is known as Load Serving Entities (LSEs) because these organizations may have decided to acquire the rest of the capacity in the real-time market [11]. Nevertheless, the RUC still may not have achieved a reliable day-ahead dispatch solution and therefore, informal OMC procedures will be used. The industry has several differing terms for OMCs, including uneconomic adjustments [1], manual dispatch [12], security corrections [13], exceptional dispatches [14], and out-of-merit energy/capacity [15].

The current approach taken by market operators today is to solve a deterministic unit commitment formulation. MISO's approach [16] is similar, where a SCUC is first solved and the dispatch is reviewed by their operators with their deliverability test until the day-ahead dispatch solution is approved. Approximations in the market model require MISO operators to review the day-ahead dispatch solution; any action taken by the operator that modifies the day-ahead dispatch solution is an OMC. This process is displayed in Figure 1.2 below.

System operators could solve a stochastic unit commitment formulation [17], but these formulations still include approximations, such as modeling the network with direct-current optimal power flow (DCOPF) instead of a more realistic alternating-current optimal power flow (ACOPF). In [18], the complexity required in the unit commitment model is discussed.

Due to all the approximations and limitations within the day-ahead market, OMCs are needed to obtain a dispatch solution that is feasible and operates within reliability standards, but implementing OMCs increases the total system costs. In CAISO's system,

OMCs accounted for \$43 million in 2011, reduced to \$34 million in 2012 [19]. In 2006, ERCOT reported that it acquired approximately \$80 million worth of OMCs to ensure the reliability of their system [20]. CAISO, ERCOT, and SPP briefly state their procedures with OMCs in their respective day-ahead market procedures [1]-[4], [9].

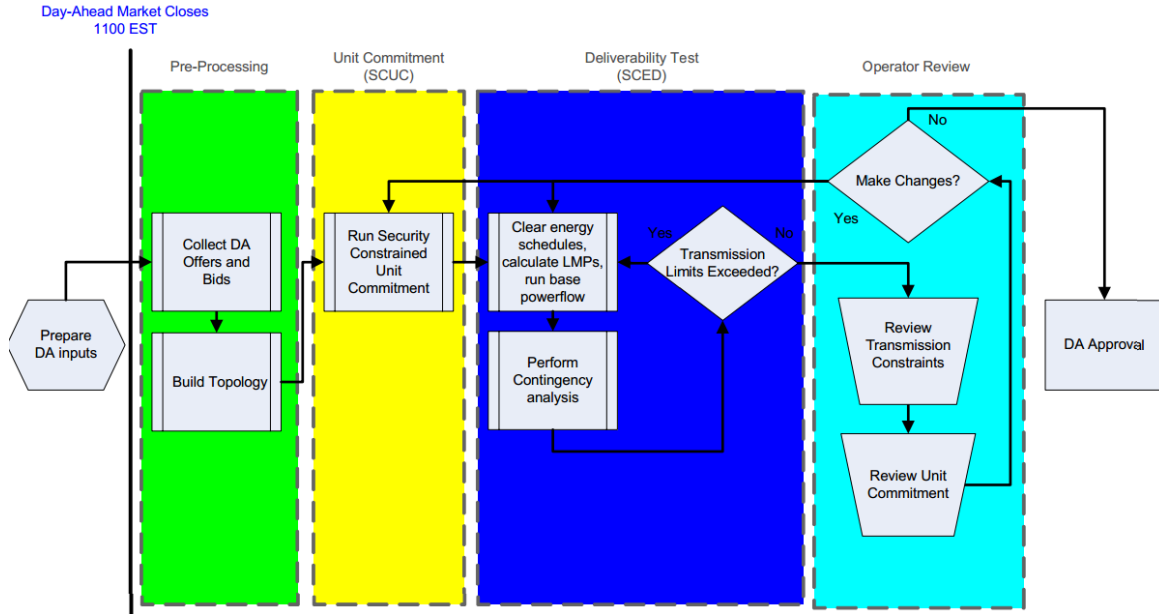


Figure 1.2 MISO Day-Ahead Market Process [16].

1.4 Thesis Organization

A total of seven chapters are included in this thesis. Chapter 1 introduces the scope of the research area and includes a survey of the literature and an outline of the thesis organization. Chapter 2 presents a background of a deterministic SCUC day-ahead formulation, including the approximation made for optimal power flow (OPF) within typical SCUC formulations. Chapter 3 contains an industry review of constraint relaxation practices for various energy markets. In Chapter 4, a modified version of the day-ahead unit commitment formulation is presented with applicable constraint relaxations. Chapter

5 investigates the effects of two different penalty price schemes for reserve relaxations on $N-1$ security and market outcomes. Chapter 6 describes a contingency analysis tool developed to check for $N-1$ reliability along with specialized algorithms and heuristics that were utilized to guarantee $N-1$ reliability. The final chapter is devoted to concluding remarks.

2. BACKGROUND

2.1 Introduction

To replicate the approach that an ISO or RTO might take for allocating resources in the day-ahead setting, the fundamental practices must be stated, especially the approximations these organizations make when solving a deterministic SCUC. To account for the transmission network, a derivation of the linearized DCOPF is described in Chapter 2.2 and subsequently in Chapter 2.3 followed by one formulation for a day-ahead SCUC. In Chapter 2.4 an example of the impact constraint relaxation practices have on a linear program's dual variables is presented. Chapter 2.5 describes a DC-based contingency analysis model that tests the SCUC dispatch solution for $N-1$ reliability while Chapter 2.6 presents an extensive-form SCUC that minimizes base-case (no contingency state) that accounts for post-contingency states. Finally, a summary is given in Chapter 2.7.

2.2 Optimal Power Flow Formulation

The process to optimally schedule the delivery of power is a challenging problem for system operators today. In day-ahead markets operated by ISOs, operators seek the least costly dispatch solution that delivers power while guaranteeing reliability. Due to the complexity of the problem, some assumptions must be made. One main assumption is how the transmission network is modeled. In the unit commitment models developed in this thesis, a DCOPF formulation is utilized and derived based on [21].

A true representation of the network would include an Alternating Current Optimal Power Flow (ACOPF). Starting with the π -equivalent circuit of a transmission line

shown in Figure 2.1, the real and reactive power flow equations over an individual line can be derived. Note that the index k represents the particular transmission line, while m and n represent the ‘from’ and ‘to’ buses connected by the transmission line.

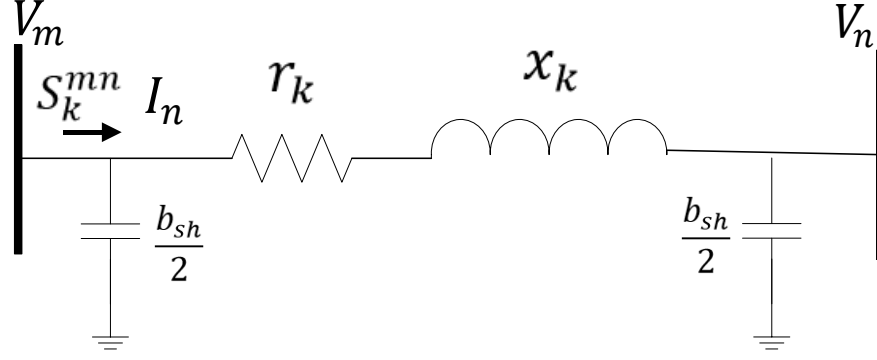


Figure 2.1. The Π -Equivalent Circuit of a Transmission Line.

$$z_k = r_k + jx_k \quad (2.1)$$

$$y_k = \frac{1}{z_k} = \frac{1}{r_k + jx_k} \times \frac{r_k - jx_k}{r_k - jx_k} = \frac{r_k - jx_k}{r_k^2 + x_k^2} = \frac{r_k}{r_k^2 + x_k^2} - \frac{jx_k}{r_k^2 + x_k^2} = g_k + jb_k \quad (2.2)$$

$$V_m = |V_m| \angle \theta_m = |V_m| (\cos \theta_m + j \sin \theta_m) \quad (2.3)$$

$$V_n = |V_n| \angle \theta_n = |V_n| (\cos \theta_n + j \sin \theta_n) \quad (2.4)$$

$$\tilde{I}_m = V_m \left(\frac{jb_{sh}}{2} \right) + \frac{\tilde{V}_m - \tilde{V}_n}{z_k} = \tilde{V}_n \left(\frac{jb_{sh}}{2} \right) + y_k (\tilde{V}_m - \tilde{V}_n) \quad (2.5)$$

$$I_m = V_M \left(\frac{jb_{sh}}{2} \right) + (g_k + jb_k) (\tilde{V}_m - \tilde{V}_n) = V_m \left(g_k + jb_k + \frac{jb_{sh}}{2} \right) - V_n (g_k + jb_k) \quad (2.6)$$

$$S_k^{mn} = V_m I_m^* = V_m \left(V_m \left(g_k + jb_k + \frac{jb_{sh}}{2} \right) - V_n (g_k + jb_k) \right)^* \quad (2.7)$$

$$S_k^{mn} = |V_m|^2 \left(g_k - jb_k - \frac{jb_{sh}}{2} \right) - V_m V_n (g_k - jb_k) \quad (2.8)$$

$$S_k^{mn} = |V_m|^2 \left(g_k - jb_k - \frac{jb_{sh}}{2} \right) - (|V_m| |V_n| \angle \theta_m - \theta_n) (j_k - jb_k) \quad (2.9)$$

$$S_k^{mn} = |V_m|^2 \left(g_k - jb_k - \frac{jb_{sh}}{2} \right) - |V_m| |V_n| (\cos(\theta_m - \theta_n) + j \sin(\theta_m - \theta_n)) (g_k - jb_k)$$

(2.10)

$$S_k^{mn} = |V_m|^2 \left(g_k - jb_k - \frac{jb_{sh}}{2} \right) - |V_m||V_n|(g_k \cos(\theta_m - \theta_n) - jb_k \cos(\theta_m - \theta_n) + jg_k \sin(\theta_m - \theta_n) + b_k \sin(\theta_m - \theta_n)) \quad (2.11)$$

$$S_k^{mn} = |V_m|^2 \left(g_k - jb_k - \frac{jb_{sh}}{2} \right) - |V_m||V_n|(g_k \cos(\theta_m - \theta_n) + jb_k \sin(\theta_m - \theta_n) - jg_k \sin(\theta_m - \theta_n) - b_k \cos(\theta_m - \theta_n)) \quad (2.12)$$

From (2.12), the complex power sent from bus m to bus n was derived. The associated real and reactive power flows can now be separated as follows:

$$S_k^{mn} = P_k^{mn} + jQ_k^{mn} \quad (2.13)$$

$$P_k^{mn} = |V_m|^2 g_k - |V_m||V_n|(g_k \cos(\theta_m - \theta_n) + b_k \sin(\theta_m - \theta_n)) \quad (2.14)$$

$$Q_k^{mn} = -|V_m|^2 \left(b_k + \frac{b_{sh}}{2} \right) - |V_m||V_n|(g_k \sin(\theta_m - \theta_n) - jb_k \cos(\theta_m - \theta_n)) \quad (2.15)$$

Now that equations have been derived for real and reactive power flow, an ACOPF dispatch problem can be completed. The control variables associated with the power flow equations in the ACOPF are the voltages (V_m and V_n) and the bus angles (θ_m and θ_n). It is typically assumed that voltage levels must remain within five percent of their rated values and this is reflected in (2.20). Another criterion is that the angle difference between two buses cannot exceed the stability limit, approximately 0.52 radians. Equations (2.16) to (2.22) represent the ACOPF.

$$\text{minimize } \sum_g c_g P_g \quad (2.16)$$

$$\sum_{k \in \delta^+(n)} P_k - \sum_{k \in \delta^-(n)} P_k + \sum_{g \in g(n)} P_g = d_n \quad \forall n \quad (2.17)$$

$$\sum_{k \in \delta^+(n)} Q_k - \sum_{k \in \delta^-(n)} Q_k + \sum_{g \in g(n)} Q_g = q_n \quad \forall n \quad (2.18)$$

$$P_k^2 + Q_k^2 \leq (S_k^{max})^2 \quad \forall k \quad (2.19)$$

$$0.95 \leq V_n \leq 1.05 \quad \forall n \quad (2.20)$$

$$-0.52 \leq \theta_m - \theta_n \leq 0.52 \quad \forall n \quad (2.21)$$

$$0 \leq P_g \leq P_g^{max} \quad \forall g \quad (2.22)$$

Due to the added complexity of the unit commitment models, operators linearize the power flow equations to derive what is called a DCOPF. The assumptions for the DCOPF are as follows: (1) reactive power is ignored; (2) conductance (g_k) in the transmission lines is much smaller than the susceptance (b_k) and, therefore, it is assumed that the conductance is negligible ($g_k = 0$); (3) the angle difference between bus (i) and (j) is relatively small and, therefore, approximations are made to simplify the trigonometric terms: $\cos(\theta_i - \theta_j) \approx 1$ and $\sin(\theta_i - \theta_j) \approx (\theta_i - \theta_j)$; (4) the voltages of V_i and V_j are assumed to be 1 per unit. With a linear objective function, the DCOPF is a linear program (LP). The DCOPF formulation becomes,

$$\text{minimize } \sum_g c_g P_g \quad (2.23)$$

$$\sum_{k \in \delta^+(n)} P_k - \sum_{k \in \delta^-(n)} P_k + \sum_{g \in g(n)} P_g = d_n \quad \forall n \quad (2.24)$$

$$-P_k^{max} \leq P_k \leq P_k^{max} \quad \forall k \quad (2.25)$$

$$P_k - b_k(\theta_n - \theta_m) = 0 \quad \forall k \quad (2.26)$$

$$0 \leq P_g \leq P_g^{max} \quad \forall g \quad (2.27)$$

2.3 Security Constrained Unit Commitment Model

The SCUC model, used for this study, is a deterministic mixed integer program, which resembles the deterministic SCUC that is used in day-ahead market models. Its solution is used to produce the day-ahead market solution. The model presented is a mixed integer linear program, with the objective of:

$$\text{minimize } \sum_g \sum_t (c_g^{op} P_{gt} + c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) \quad (2.28)$$

The total system cost (2.28) is represented by linear cost term in $c_g^{op}P_{gt}$, where c_g^{op} is the linear fixed cost and P_{gt} is the supply for each generator during each time period. The fixed costs are represented by binary variables (whose value could only be 0 or 1) in u_{gt} , v_{gt} , and w_{gt} , which represent the generator status, startup indicator, and shutdown indicator. Therefore, the term $c_g^{NL}u_{gt}$ represents the fixed no-load cost term and $c_g^{SU}v_{gt} + c_g^{SD}w_{gt}$ represent the startup and shutdown costs, respectively.

The binary variables v_{gt} and w_{gt} are related to the status binary, u_{gt} , which represents the periods that a unit is committed. A generator turned on during a specific time period is represented by the binary v_{gt} , the startup variable, whereas a de-committed generator is represented by w_{gt} , the shutdown variable. These variables are restricted to a binary output because the formulation presented here does not guarantee a binary output.

$$v_{gt} \geq u_{gt} - u_{gt-1} \quad \forall g, t \quad (2.29)$$

$$w_{gt} \geq u_{gt-1} - u_{gt} \quad \forall g, t \quad (2.30)$$

The SCUC replicates generator operating constraints. For example, the minimum and maximum production levels are represented by the parameters P_g^{min} and P_g^{max} respectively. In (2.31) and (2.32), a committed generator must be between its minimum production level and its maximum production level. The variable r_{gt}^{SP} represents the spinning reserve acquired for a given generator during a specific time period and therefore the production level plus the spinning reserve must be less than the maximum supply level since in the event of a contingency, a generator cannot provide power greater than its maximum production level. Thus, the reserve acquired plus the production level must be

less than the maximum production level. These operational constraints are represented below.

$$P_{gt} \geq P_g^{min} u_{gt} \quad \forall g, t \quad (2.31)$$

$$P_{gt} + r_{gt}^{SP} \leq P_g^{max} u_{gt} \quad \forall g, t \quad (2.32)$$

Operational generator requirements extend beyond minimum and maximum production levels. Another set of requirements include minimum time up and down that a committed/de-committed generator has after a unit has been turned on or off. This is represented in (2.33) and (2.34), where the summation of the startup and shutdown binary variable is over the minimum up and down time requirement, respectively.

$$\sum_{s=t-UT_g-1}^t v_{gs} \leq u_{gt} \quad \forall g \quad (2.33)$$

$$\sum_{s=t-DT_g-1}^t w_{gs} \leq 1 - u_{gt} \quad \forall g \quad (2.34)$$

Another generator operational constraint included in the SCUC is the hourly ramp rate. For simplicity, startup and shutdown ramp rates are assumed to be the maximum production level of the generator, P_g^{max} . The ramp up and down constraints, using only hourly ramp rates, are shown in (2.35) and (2.36).

$$u_{gt-1} R_g^{HR} + v_{gt} P_g^{max} \geq P_{gt} - P_{gt-1} \quad \forall g, t \quad (2.35)$$

$$u_{gt} R_g^{HR} + w_{gt} P_g^{max} \geq P_{gt-1} - P_{gt} \quad \forall g, t \quad (2.36)$$

Apart from generator operational constraints, the unit commitment model seeks to ensure $N-1$ reliable dispatch by also acquiring reserve. Committed generators could have their production level reduced to provide spinning reserve in the case of a contingency. Reserve could also be provided in the form of non-spinning reserve from fast-start generators. The total reserve acquired from the system during a given time period must be at

least 7% of the total demand during that specific hour and greater than the largest generator production level plus any spinning reserve acquired from that generator, represented in (2.37) and (2.38). The total reserve acquired is also constrained to be at least half from spinning reserve, shown in (2.39). Furthermore, the total reserve for the given time period is also constrained to 7% of the total load, which follows [22].

$$r_t^{total} \geq \sum_n 0.07 d_{nt} \quad \forall n, t \quad (2.37)$$

$$r_t^{total} \geq P_{gt} + r_{gt}^{SP} \quad \forall g, t \quad (2.38)$$

$$\sum_g r_{gt}^{SP} \geq 0.5 r_t^{total} \quad \forall t \quad (2.39)$$

The amount of spinning reserve acquired for a committed unit is further constrained by the emergency ramp rate of the specific generator. This restriction is needed because, in case of a contingency, a generator can only move within the emergency ramp rate. Any spinning reserve acquired in the unit commitment model must also be constrained to the emergency ramp rate.

$$r_{gt}^{SP} \leq R_g^{EM} u_{gt} \quad \forall g, t \quad (2.40)$$

Non-spinning reserve can only be acquired by fast-start generators. A binary parameter FS_g is set to 1 to indicate a fast-start generator and 0 otherwise. Paired with this binary parameter, the non-spinning reserve acquired is constrained between a generator's minimum and maximum production levels for units that are not committed.

$$0 \leq r_{gt}^{NS} \leq R_g^{EM} (1 - u_{gt}) FS_g \quad \forall g, t \quad (2.41)$$

$$r_{gt}^{NS} \leq P_g^{max} (1 - u_{gt}) FS_g \quad \forall g, t \quad (2.42)$$

Based on a DCOPF, the transmission network included in the unit commitment model are constrained by (2.43) to (2.44), where (2.45) is a node balance constraint. Al-

ternatively, the line flow constraints could be formulated with the power transfer distribution factors (PTDFs) of the transmission network.

$$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall k, t \quad (2.43)$$

$$-P_k^{max} \leq P_{kt} \leq P_k^{max} \quad \forall k, t \quad (2.44)$$

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (2.45)$$

$$u_{gt}, v_{gt}, w_{gt} \in \{0,1\} \quad \forall g, t \quad (2.46)$$

There are several forms and modifications that can be made to better represent the system. For example, in another formulation presented in Chapter 4.2, the generator operation constraints governing the minimum up and down time requirements are updated such that in the day-ahead unit commitment model, the beginning and ending periods depend on each other. There are several different reserve requirement rules that could be used in an attempt to guarantee $N-1$ reliability, but these reserve requirements do not necessarily guarantee reliability.

2.4 Example of the Impact Constraint Relaxations have on the Dual Variable

In an LP or mixed integer linear program (MILP), a constraint relaxation is incorporated into the problem by adding a slack variable to the particular constraint and to the objective with a penalty price. Formulating the LP or MILP in this manner limits the dual variable associated with the relaxed constraint. As long as the slack variable is not limited, the penalty price is the maximum value of the dual variable.

Constraint relaxation is a mechanism to manage prices. When applied to a market model, presented in Chapter 4.2, the dual variable in the associated constraints will also be limited by the penalty price. Early deregulated electric energy markets only limited the

bid price of market participants (generators). However, this policy does not limit the locational market price (LMP), the price used for settling the market at that node. The LMP can be limited allowing relaxations on the node/power balance constraint in the market model. If a particular node is relaxed, the LMP is limited to the penalty price; additionally, the LMP will not exceed the set penalty price. Below is an example in Figure 2.2 and Figure 2.3.

Standard Primal Problem	Corresponding Dual Formulation
$\begin{aligned} & \text{minimize: } c_1x_1 + c_2x_2 \\ & a_{11}x_1 + a_{12}x_2 \geq b_1 \ (\lambda_1) \\ & a_{21}x_1 + a_{22}x_2 \geq b_2 \ (\lambda_2) \\ & x_1 \geq 0 \\ & x_2 \geq 0 \end{aligned}$	$\begin{aligned} & \text{maximize: } b_1\lambda_1 + b_2\lambda_2 \\ & a_{11}\lambda_1 + a_{21}\lambda_2 \leq c_1 \ (x_1) \\ & a_{12}\lambda_1 + a_{22}\lambda_2 \leq c_2 \ (x_2) \\ & \lambda_1 \geq 0 \\ & \lambda_2 \geq 0 \end{aligned}$
Primal Problem with Constraint Relaxation	Corresponding Dual Formulation of Primal with Constraint Relaxations
$\begin{aligned} & \text{minimize: } c_1x_1 + c_2x_2 + P_1s_1 + P_2s_2 \\ & a_{11}x_1 + a_{12}x_2 \geq b_1 - s_1 \ (\lambda_1) \\ & a_{21}x_1 + a_{22}x_2 \geq b_2 - s_2 \ (\lambda_2) \\ & x_1 \geq 0 \\ & x_2 \geq 0 \\ & s_1 \geq 0 \\ & s_2 \geq 0 \end{aligned}$	$\begin{aligned} & \text{maximize: } b_1\lambda_1 + b_2\lambda_2 \\ & a_{11}\lambda_1 + a_{21}\lambda_2 \leq c_1 \ (x_1) \\ & a_{12}\lambda_1 + a_{22}\lambda_2 \leq c_2 \ (x_2) \\ & \lambda_1 \leq P_1 \ (s_1) \\ & \lambda_2 \leq P_2 \ (s_2) \\ & \lambda_1 \geq 0 \\ & \lambda_2 \geq 0 \end{aligned}$

Figure 2.2. LP Example to Demonstrate the Effects of Constraint Relaxations on Dual.

The “Standard Primal Problem” exhibits hard constraints that cannot be violated, i.e., any solution found for the primal variables x_1 and x_2 , must stay within the set bounds. Notice that in the corresponding Dual Formulation, the dual variables λ_1 and λ_2 , are only restricted to be greater than zero. In the “Primal Problem with Constraint Relaxations,” constraints are relaxed by adding the slack variables s_1 and s_2 . However, relaxing the constraint means that a penalty price must be paid, P_1 and P_2 in this example. In the corresponding dual formulation, the dual variables, λ_1 and λ_2 , are now restricted and cannot exceed the corresponding penalty price, P_1 and P_2 .

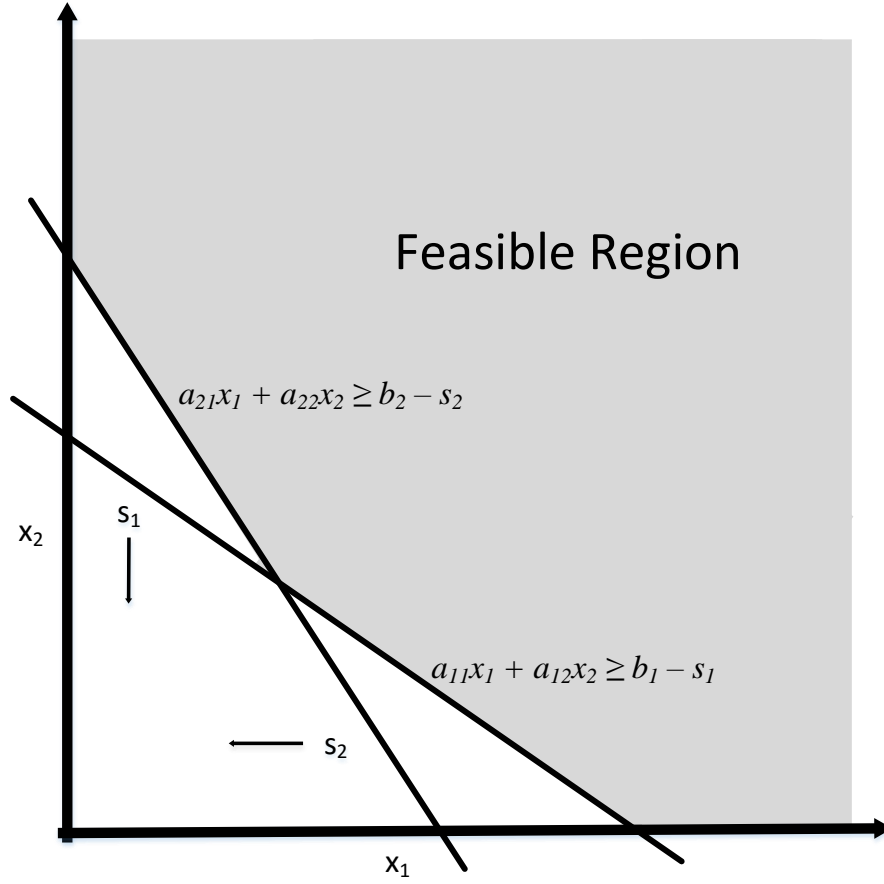


Figure 2.3. Graphical Interpretation of Relaxing a Constraint.

As demonstrated, relaxing a constraint while imposing a penalty price restricts the corresponding dual variables. When this occurs on the node balance constraint in the market model and the LMP, the basis of system settlements is restricted to the penalty price. Therefore, when CAISO performs its pricing run with a constraint relaxation on the node balance constraint with a penalty price of \$500/MWh, a price cap is imposed on the LMP by relaxing the SCUC formulation.

2.5 Contingency Analysis

Even with the reserve requirements built into the SCUC, unless all $N-1$ contingencies are explicitly accounted for in the SCUC, the resulting dispatch solution is not guaranteed to be $N-1$ reliable. The tool presented here performs a steady-state $N-1$ reliability test for each hour separately using a DCOPF formulation. The power flow on the transmission lines are allowed to exceed their designated short-term emergency limit, otherwise known as allowing for infinite transmission capacity. When this occurs, an $N-1$ violation is reported because exceeding the short-term emergency limit means that the system is unable to deliver power reliably within the 15-minute interval (Figure 2.4). Within this interval, the system itself must respond to the contingency because this time interval allows for little operator action. Due to model tests for steady-state response with a DCOPF formulation, dynamic and AC feasibility testing must still be performed on the SCUC dispatch solution. However, it should be noted that a similar contingency analysis tool is offered by the industry vendor Alstom today [23].

To check whether the dispatch solution is $N-1$ feasible, contingency analysis is performed with the objective of minimizing line violations. In the model given below in Equations (2.47) to (2.58), the contingency analysis model allows for infinite transmission capability, which solves for each scenario c separately. The system is said to be $N-1$ infeasible when the line flow is above the emergency rated limits; that is s_{kt}^+ and s_{kt}^- have a value other than zero. Here only the model with generator contingencies is given. A contingency analysis model with transmission asset contingencies can be seen in Appendix B.

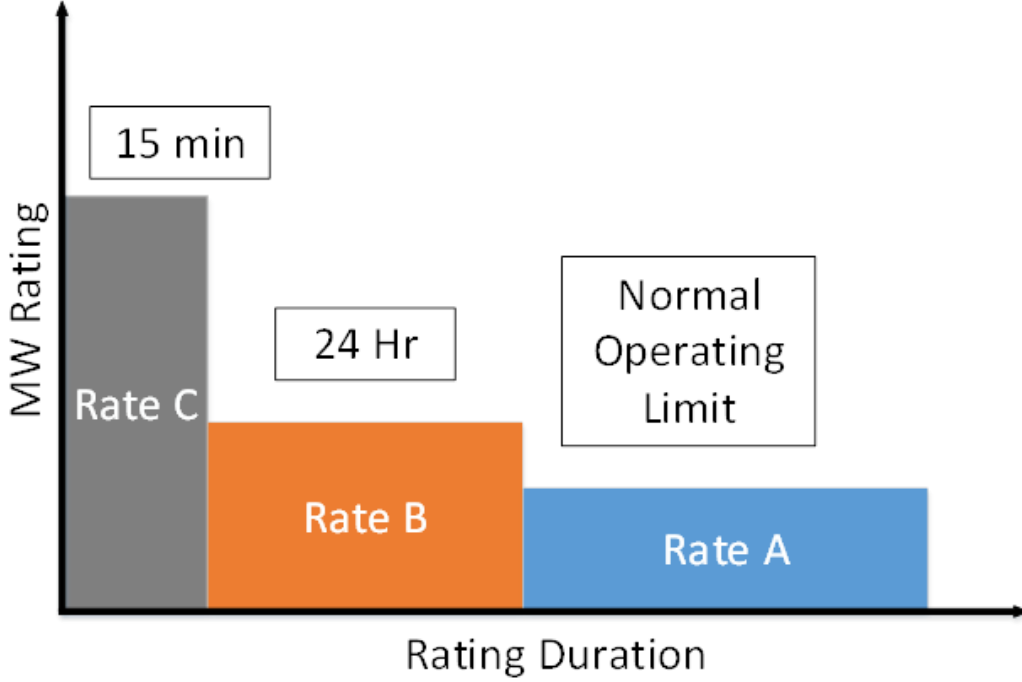


Figure 2.4. Transmission Line Ratings Where Rate C is the Short Term Emergency Rating, Rate B is the Long Term, and Rate A is the Rating During Normal Operating States, i.e., No Contingency Present.

When a contingency occurs, committed generators are allowed to provide spinning reserve acquired in the SCUC model. During contingency analysis, committed units move from their current output to new dispatch levels that are plus or minus their emergency ramp rate. These are represented by the constraints shown in (2.48) and (2.49). Generators are still restricted to minimum and maximum limits and thus are enforced in the CA model by (2.48) and (2.49). Parameter $N1_g$ represents the contingency generator unit. In this case, the parameter is set to a value of zero. All generators are represented with a value of one because only one generator is removed during a simulation, whose value is set to zero. Other parameters include u_{gt} and P_{gt} , which represent the generator

status and supply that was determined from the SCUC. The post-contingency supply level is represented by the variable, \hat{P}_{gt} .

$$\text{minimize } \sum_k \sum_t s_{kt}^+ + s_{kt}^- \quad \forall c \quad (2.47)$$

$$\hat{P}_{gt} \leq N1_g \bar{u}_{gt} (\bar{P}_{gt} + R_g^{EM}) \quad \forall g, t \quad (2.48)$$

$$\hat{P}_{gt} \geq N1_g \bar{u}_{gt} (\bar{P}_{gt} - R_g^{EM}) \quad \forall g, t \quad (2.49)$$

$$\hat{P}_{gt} \leq N1_g P_g^{max} \bar{u}_{gt} \quad \forall g, t \quad (2.50)$$

$$\hat{P}_{gt} \geq N1_g P_g^{min} \bar{u}_{gt} \quad \forall g, t \quad (2.51)$$

Fast start generators participated in mitigating post contingency line violations by providing non-spinning reserve. In the contingency analysis, model fast-start generators are allowed to provide additional capacity up to their maximum supply rating. The minimum supply rating is relaxed for fast-start generators, which do have a minimum capacity, by allowing only fast-start generators to be dispatched anywhere from zero to their maximum capacity. This relaxation is made such that the contingency analysis tool does not become a MIP.

$$\hat{P}_{gt} \leq N1_g P_g^{max} \quad \forall g, t, FS_g = 1 \quad (2.52)$$

$$\hat{P}_{gt} \geq 0 \quad \forall g, t, FS_g = 1 \quad (2.53)$$

The line flow constraints still hold in the contingency analysis model, but the transmission limit capacity constraints are modified by setting the transmission assets to the minimum and maximum flow of their emergency limits. Furthermore, the constraint is modified to allow for these transmission constraints to be violated through the use of the slack variables, s_{kt}^+ and s_{kt}^- . While the contingency analysis tool attempts to minimize these slack variables, if either of these is greater than zero for a given contingency, then a

violation is recorded because the system has been determined to be unreliable for that particular contingency. Therefore, the market solution is said to be $N-1$ infeasible.

$$-P_{kt}^{max,c} - s_{kt}^- \leq P_{kt} \leq P_k^{max,c} + s_{kt}^+ \quad \forall k, t \quad (2.54)$$

$$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall k, t \quad (2.55)$$

$$s_{kt}^+ \geq 0 \quad \forall k, t \quad (2.56)$$

$$s_{kt}^- \geq 0 \quad \forall k, t \quad (2.57)$$

Finally, as before, the node balance constraint is also required for this model, which represents power flow in and out of the transmission lines connected to the node that must equal the supply of any generator at that node, less any demand.

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (2.58)$$

2.6 Extensive-Form Stochastic Unit Commitment

Another market model used is the extensive-form stochastic unit commitment model (ESCUC), which guarantees an $N-1$ feasible dispatch solution. Originally this model was developed by [24], and included the capability of transmission switching.

From [24], the objective function was modified to include the fixed generator cost, also known as no-load cost. Furthermore, the supply variable was updated to include all scenarios, so that now the supply variable is P_{gct} where c is the current scenario and when c is zero, i.e., no contingencies. However, the objective function shown in (2.59) only incorporates the scenario with no contingencies present because the model will account for all generator and non-radial transmission contingencies. The model will only seek to minimize the cost for the scenario with no contingencies.

$$\text{minimize } \sum_g \sum_t (c_g^{op} P_{g0t} + c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) \quad (2.59)$$

As with the previous SCUC model, the ESCUC includes binary variables that indicate the generator status (u_{gt}), generator startup (v_{gt}), and generator shutdown (w_{gt}). The minimum up- and down-time related to each generator also utilizes this variable.

$$v_{gt} \geq u_{gt} - u_{gt-1} \quad \forall g, t \quad (2.60)$$

$$w_{gt} \geq u_{gt-1} - u_{gt} \quad \forall g, t \quad (2.61)$$

$$\sum_{s=t-UT_g+1}^t v_{gs} \leq u_{gt} \quad \forall g, t \quad (2.62)$$

$$\sum_{s=t-DT_g+1}^t w_{gs} \leq 1 - u_{gt} \quad \forall g, t \quad (2.63)$$

Unlike the original SCUC model used earlier, a PTDF formulation is used. PTDFs indicate the amount of power that flows from one particular bus to a reference bus through each transmission line, most of which are very close to zero. PTDFs change depending on the scenario. For transmission line/assets contingencies, the topology of the network changes, but these PTDFs can be calculated offline to be included in the model. The PTDF formulation modifies the node balance constraint as well as the line limit constraints. Additionally, instead of using the variable P_{kt} for the line flow variable, a variable for the net-injection at a bus is used.

$$P_{nct}^{inj} + \sum_{g \in g(n)} P_{gct} = d_{nt} \quad \forall n, c, t \quad (2.64)$$

$$-P_k^{max} \leq \sum_n P_{n0t}^{inj} PTDF_{nk0}^{REF} \leq P_k^{max} \quad \forall k, c = 0, t \quad (2.65)$$

$$-P_k^{max(EM)} N1_{ec} \leq \sum_n P_{nct}^{inj} PTDF_{nkc}^{REF} \leq P_k^{max(EM)} N1_{ec} \quad \forall k, c \neq 0, t \quad (2.66)$$

An advantage of the extensive-form stochastic unit commitment model is that the formulation is reflective of all pre- and post-contingency scenarios. Therefore, the dual of Equation (2.64), which is typically called the locational marginal price (LMP), reflects

the cost of delivering the next MWh in both the normal operating state and the post-contingency states that are modeled to guarantee $N-1$ reliability.

As part of the formulation, the parameter $N1_{ec}$ indicates the current element e that is removed due to contingency scenario c , which includes generators and non-radial transmission assets. Only one element generator or transmission line is removed for each contingency scenario. Thus the element removed for the current scenario is assigned a value of zero to indicate the element has been removed, while all other elements are assigned a value of one.

Generator bounds are applied to each generator with the addition of these bounds being applied to each scenario. These constrain the generator supply between its minimum and maximum rating, which could be viewed in (2.67) and (2.68).

$$P_{gct} \geq P_g^{min} u_{gt} N1_{ec} \quad \forall g, c, t \quad (2.67)$$

$$P_{gct} \leq P_g^{max} u_{gt} N1_{ec} \quad \forall g, c, t \quad (2.68)$$

The ramp rate constraints are similar to that of the SCUC, where only an hourly ramp rate is incorporated into the model. These constraints only apply to scenario zero when no contingencies are present, whose supply is represented by P_{g0t} . For all other scenarios represented by P_{gct} where c is greater than zero, the supply for that scenario is constrained to that obtained for the base case scenario, P_{g0t} , plus or minus the emergency ramp rate. In other words, the model restricts the base case supply to account for all contingencies by allowing the $N-1$ supply to move only within its emergency limits.

$$P_{g0t} - P_{g0t-1} \leq R_g^{HR} u_{gt-1} + P_g^{max} (1 - u_{gt-1}) \quad \forall g, t \quad (2.69)$$

$$P_{g0t-1} - P_{g0t} \leq R_g^{HR} u_{gt} + P_g^{max} (1 - u_{gt}) \quad \forall g, t \quad (2.70)$$

$$P_{gct} - P_{g0t} \leq R_g^{EM} u_{gt} \quad \forall g, (g \neq c), t \quad (2.71)$$

$$P_{g0t} - P_{gct} \leq R_g^{EM} u_{gt} \quad \forall g, (g \neq c), t \quad (2.72)$$

In this ESCUC model, reserve requirements are not included because all $N-1$ contingencies, which include generator and non-radial transmission assets, are explicitly incorporated through $N1_{ec}$ parameter. The result of this unit commitment model is a feasible $N-1$ day ahead dispatch solution.

This model was also modified to take the output of the SCUC, presented in Chapter 2.3, to find the least cost $N-1$ feasible dispatch solution that could be obtained from the commitment solution found by the SCUC. Only one additional constraint was needed and is given below in Equation (2.73), which represents constraining the ESCUC model to the output of day-ahead commitment solution and is represented by the parameter \bar{u}_{gt} . The ESCUC model could commit additional generators and was allowed to change the dispatch of the entire system accordingly to obtain a feasible $N-1$ solution. The output of this modified model is listed as ESCUC-UC.

$$\hat{u}_{gt} \geq \bar{u}_{gt} \quad \forall g, t \quad (2.73)$$

In the ESCUC model, (2.59) to (2.72) provide the least costly $N-1$ reliable solution. This model still approximates the network with a DCOPF formulation instead of a full ACOPF. The model guarantees $N-1$ security assuming a 10 min time frame. The ESCUC-UC is the same formulation as the ESCUC model, with the constraint the only addition, as in (2.73), which forces the model to start with the original dispatch solution from the SCUC. The ESCUC-UC model subsequently finds the least costly $N-1$ reliable solution for the initial dispatch solution from the SCUC. The results from these models are used for comparison purposes with the OMC procedures.

2.7 Summary

The DCOPF represents an approximation of the real power flow throughout the transmission network. The approximations made to attain the DCOPF are necessary; otherwise, the SCUC model would not be a mixed integer linear program due to the non-linear constraints that would have been included through an ACOPF formulation. The day-ahead SCUC model presented is similar to what an ISO, RTO, or even a vertically integrated utility might use to determine which generators to commit the next day. Other formulations could be used. For example, the SCUC formulation used by industry includes constraint relaxations practices and the effects these practices have on linear programs was shown. After a SCUC dispatch solution is produced, it can be tested for $N-1$ reliability using the contingency analysis model presented in this chapter. Finally, an extensive-form SCUC that optimizes the base-case (no contingency) while considering post-contingency states is reviewed. All models presented in this chapter are used as the basis of the research presented throughout this thesis.

3. INDUSTRY REVIEW OF CONSTRAINT RELAXATION PRACTICES

3.1 Introduction

Electric power grids are among the most complex engineered systems today. To ensure a reliable and continuous supply of electric power, operators attempt to control their portion of the electric grid in the most efficient manner possible regardless of whether the operator works for ISO, RTO, or a vertically integrated utility. Operators must manage their generation fleet, which has complex operating requirements, while maintaining system synchronism and managing transmission assets throughout their control area. Operators must also cope with the increasing presence of variable generation (e.g., photovoltaic solar and wind power) and limited energy storage capability all while meeting stringent reliability standards. The North American Electric Reliability Corporation (NERC) has many standards guiding operator action. One such required standard is *N-1* reliability, where the loss of a single generator or non-radial transmission asset does not cause involuntary load shedding. NERC states that operators must check for any potential *N-1* violations every 30 minutes and if there is a potential violation, regain *N-1* reliability within 30 minutes [25]-[26]. The Western Electric Coordinating Council (WECC), a regional authority, advises *N-1* reliability be checked every 15 minutes [27]. Since *N-1* reliability is checked at various time intervals, this standard is not continually enforced; furthermore, the operator must regain *N-1* reliability 30 minutes after observing that the criterion has not been met. As a result, there are situations when operators allow short-term violations to occur, but later correct for those violations in order to meet *N-1* requirements.

System operators who manage the auction of wholesale energy cannot incorporate all of these requirements into their market management systems (MMS) due to the added computational complexity. Even with a linearized market, some constraints become too costly to meet and create an infeasibility. With the incorporation of constraint relaxations into the MMS, operators can attain a market solution. The market solution must then be corrected to meet local and federal standards. This must be done regardless of whether or not the MMS chooses to relax certain constraints because of all the approximations incorporated into the MMS.

In this report, an investigation is conducted into the current constraint relaxations practices utilized by ISOs, the potential market outcomes of these practices, and finally their effect on system reliability.

3.2 Day-Ahead Scheduling Process

Today, market models can only approximate some of these complex operating, reliability, and transmission requirements while trying to optimize the dispatch of the generation fleet. Even with continued advances in algorithmic performance and hardware, such optimization problems continue to require an engineered market structure with various approximations that impact the schedule of energy and ancillary services along with the corresponding market prices and settlements. Therefore, instead of forcing market models to abide by strict, although approximated constraints, market designers choose to relax some of these constraints by adding slack variables. However, to discourage the optimization algorithm from readily choosing to violate the constraint with no consequence, the system must pay a pre-determined penalty price, i.e., the slack variables are incorpo-

rated into the objective function with a chosen penalty price. Although these practices have been approved and implemented today, little is understood regarding the impacts on market solutions, reliability, and stability of the system. Furthermore, there has been limited evaluation of the impacts of such market design practices.

System operators can potentially receive several benefits from employing constraint relaxations practices in market models. First, constraint relaxations allow for the potential to obtain gains in market surplus with small relaxations. At times, strictly enforcing a constraint, which is an approximation itself, can substantially increase operating costs while the enforcement of that constraint to such a stringent requirement may serve a minimal purpose. Furthermore, the approximations themselves may result in the optimization model being infeasible even if a real-world solution were to exist.

Another benefit of constraint relaxations in market models is that these practices allow operators to manage prices. Previously, markets were designed with a bid cap, which would limit the bid (the price) that market participants could submit to the market for their service. This approach was intended to place a cap (a ceiling) on market prices, the locational marginal prices (LMP). To the surprise of early market designers, the LMPs were not (and are not) limited by imposing a restriction on the bid values themselves; instead, LMPs can be limited by relaxing the node balance constraint with slack variables and then placing a penalty on the slack. This makes it more economical to always have the slack artificially create production at a bus if the delivery cost exceeds the penalty price. As a result, the penalty price becomes a cap on the LMP.

While both MMS and constraint relaxation practices vary among industry members, the general process is similar to that shown in Figure 3.1. Details of the different

market software tools that ISOs utilize are given in [28]. Initially, ISOs will collect bids for the day-ahead market (DAM), where market participants bid to either purchase or supply energy and ancillary services. Some participants, typically known as load-serving entities (LSEs), purchase energy in the day-ahead market while other participants, known as independent power producers (IPPs), sell energy. A virtual bidder could take either position in the market. The ISO attempts to maximize the market surplus based on these offers relative to operating and reliability requirements. Due to the complexity of these requirements, approximations must be made in the market SCUC model. This includes using a DCOPF formulation instead of a non-linear ACOPF formulation. Similarly, proxy reserve requirements are implemented in an attempt to guarantee $N-1$ reliability instead of explicitly modeling all $N-1$ scenarios in the SCUC; note that implementing the latter creates a stochastic program. Approximations are needed even for smaller systems because the computational complexity would increase immensely. Different methods for the SCUC are detailed in [29].

Even though ISOs approximate operating and reliability requirements in the SCUC, these organizations allow constraints to be relaxed. When a constraint is relaxed, the market pays a penalty, which must be offset by greater benefits in terms of market surplus. Relaxations allow ISOs to obtain solutions that would otherwise be infeasible due to approximations made within the SCUC. ISOs then modify the proposed market-based dispatch solution until a feasible solution is obtained. Most frequently, the solution is not AC feasible because of the assumptions made regarding power flow (using a DCOPF formulation). Operators will make any changes that are necessary, including

running contingency analysis, to obtain a feasible dispatch solution. This process can be viewed in Figure 3.2 [16].

Once the DAM is solved, awards are given to generators to produce power and load-serving entities must pay for power acquired in the day-ahead market. However, some LSEs might not have purchased adequate capacity to serve their customers throughout the entire day and would have to acquire the additional energy in the real-time market.

To ensure adequate capacity is available during real-time operations, after solving the DAM SCUC, ISOs will solve a reliability unit commitment (RUC), also referred to as a residual unit commitment problem using an ISO-based forecasted demand and will remove all artificial bids from virtual bidders. The RUC is one of many additional steps that take place during the adjustment period in the day-ahead scheduling process [11]. A natural separation in forward and spot prices can occur because the day-ahead (forward) market and RUC are separate and the RUC solution will influence the real-time (spot) market [30]. For the purpose of both improving the overall system efficiency as well as reducing this potential market distortion, note that at least one ISO (CAISO) is considering merging their RUC model with their DAM model to create a unified DAM-RUC model [31].

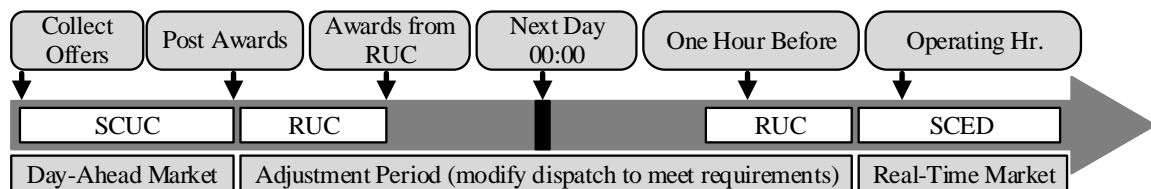


Figure 3.1. General Day-Ahead to Real-Time Market Process Adapted from ERCOT

[32].

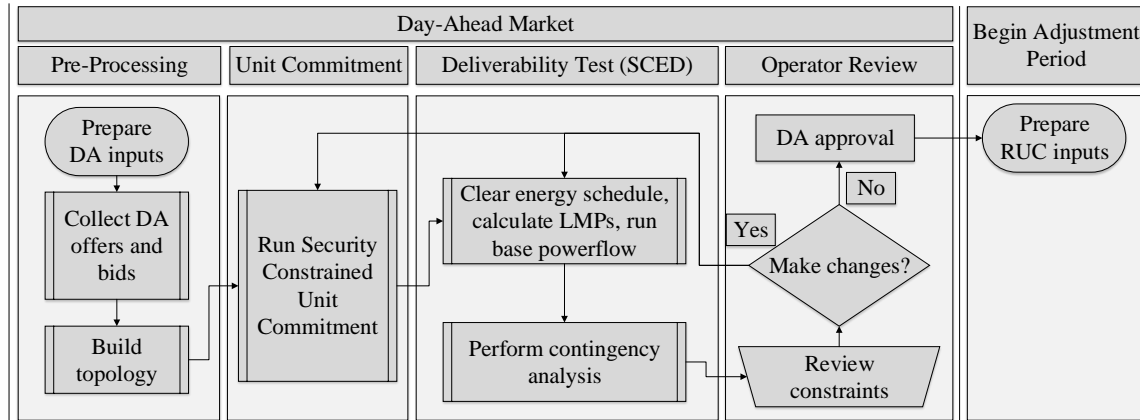


Figure 3.2. Modified Day-Ahead Market Process for MISO [16].

The real-time (spot) market opens after the day-ahead market has cleared. During real-time operations, ISOs typically solve a SCED problem and the SCED includes constraint relaxations as well. The SCED only models a portion of the transmission network as the operator will choose what constraints to enforce based on the flags provided by the real-time contingency analysis (RTCA) tool and the energy management system (EMS). Since the market SCED model also includes constraint relaxations, when the operators choose what constraints to model within the SCED, the operator may de-rate transmission thermal limits (steady-state limits) to ensure the SCED does not result in a constraint relaxation that violates the actual steady-state limits; this is possible since the EMS has a bias factor built into it that the operator can adjust (the operator can adjust this bias factor to de-rate the line's thermal rating or can use the bias factor to allow the flow to exceed the thermal limit). However, operators managing the SCED may not include all requirements so they will have to correct for approximations and relaxations. For example, if a transmission line's flow is close to its limit, the EMS will warn the operator that actions are necessary to correct for the violations to ensure that the system is secure, including de-rating the transmission line the next time the operator runs the SCED.

3.3 California Independent System Operator (CAISO)

CAISO has both a forward market and a spot market for energy transactions known as the Integrated-Forward Market (IFM) and the Real-time Market (RTM), respectively [1]. As part of their day-ahead procedures, CAISO also runs a RUC. CAISO applies constraint relaxations in all three stages. In both markets operated by CAISO, the IFM and RTM are solved twice. The first time either market is solved is known as the “scheduling-run,” for which CAISO applies large penalty prices to ensure that the market attempts to utilize the bids posted by the market participants before relaxing any of the constraints [9]. The outputs of the scheduling runs are used to determine the dispatch schedule. The results are then passed to the pricing run where only small deviations from the scheduling run’s dispatch schedule are allowed. The pricing run is different as the penalty prices are much lower in the pricing run. For example, within both the IFM and RTM, the energy/node balance constraint can be relaxed at a penalty price of \$6,500/MWh within the scheduling run; however, when solving the pricing run, the penalty is lowered to \$500/MWh. As such, the scheduling run can be interpreted to determine the primal solution (dispatch schedule) while the pricing run is used to determine the dual solution (the market prices) [33]. While this procedure has been approved by the Federal Energy Regulatory Commission (FERC) and agreed upon by the stakeholders in CAISO, this could be seen as price distortion. The scheduling run is being determined with constraint relaxations based on higher penalty prices; the resulting primal solution is kept the same but the resulting prices from the scheduling run are not used even though those prices are based on the dual solution that corresponds to the scheduling run’s primal solution. Instead, the prices are based on what comes from the pricing run, where there

are much lower penalty prices, resulting in much lower price caps (i.e., this is done for the purpose of price control).

After obtaining results from the scheduling and pricing run, CAISO solves a RUC model to ensure adequate capacity is acquired for the next day. Like the IFM, the RUC includes constraint relaxations, including the relaxation of the energy/node balance constraint and transmission limit constraints.

Due to the approximations made in these models, CAISO has to perform “exceptional dispatches” to guarantee reliability. In 2011 and 2012, CAISO paid out \$43 and \$34 million, respectively, for exceptional dispatches. CAISO even recognized that some of the constraint relaxation practices utilized in their markets could have resulted from the need for exceptional dispatches [14].

3.4 Midcontinent Independent System Operator (MISO)

MISO’s reach is the largest among ISOs in North America [34]. Once MISO determines the cleared energy and ancillary services from the DAM SCUC, operators subsequently check system reliability by performing contingency analysis. The resulting output from the contingency analysis is reviewed. If operators determine the day-ahead schedule is unreliable, the operator will either choose to resolve the SCUC or perform an out-of-market correction [16], [35]-[36].

After the MISO DAM process is completed and the schedule has been approved, MISO begins the process anew with the reliability assessment commitment (RAC), also known as a RUC. Similarly, MISO uses their version of the RUC to commit additional generation capacity to ensure adequate supply for the next operating day.

During the RTM, MISO solves a SCED to re-dispatch generators to fulfill demand and manage congestion. Due to time constraints, operators will ignore certain constraints, which might include ignoring portions of the transmission network. As a result, violations could occur in real-time. MISO has indicated that operators will attempt to avoid violations by manually de-rating line ratings when solving the SCED to avoid overloads that could be violated due to the constraint relaxation procedures [37].

Previously, MISO discontinued the use of a “constraint relaxation algorithm” [38]-[39]. In [40], the authors state that the constraint relaxation procedures artificially decrease the actual congestion present in the system during real-time operations. Today within SCED, constraints are assigned marginal value limits (MVL), which is the same as applying a penalty price. The MVL caps the dual variable of the corresponding constraint. MISO has declared these values in [40].

In [41], MISO has updated some of the MVLs to staircase demand curves. For example, a transmission line with a voltage level greater than 161kV has an MVL of \$1000/MWh when the constraint exceeds its limit until it reaches 102% of its rating. Above that level, the model sets the penalty price at \$2000/MWh. Transmission lines at other levels have different MVL prices, but still exhibit a stepwise curve.

3.5 Electric Reliability Council of Texas (ERCOT)

The DAM managed by ERCOT, which acquires energy and ancillary services [32], is solved by utilizing a multi-hour mixed integer programming algorithm that seeks to maximize market surplus for the entire day. The DAM is a unit commitment optimization problem that utilizes constraint relaxation practices similar to other ISOs and where

the market penalizes the system when violating these constraints, typically with a set penalty price.

However, ERCOT uses a different constraint relaxation structure with its node balance constraint. Like other ISOs, it can be violated either positively, when more generation is acquired artificially, or negatively, when generation is reduced artificially. However, unlike other ISOs, violations are penalized via a step-wise function [5]. The penalty prices for transmission constraints are dependent on the voltage level. Furthermore, ERCOT stipulates that the penalty factors used in the DAM can be set (adjusted) by the operator. Similar practices occur in real-time operations [42].

3.6 New York Independent System Operator (NYISO)

NYISO employs constraint relaxation practices in both their SCUC and real-time scheduling models by utilizing demand curves that reflect scarcity [43] and serve the same purpose as constraint relaxations used for price control. Some of these demand curves are either fixed or stepped. For instance, NYISO sets a “Demand Curve Price” of 4000 \$/MWh for relaxing any transmission constraint. Conversely, the price for relaxing the 30-minute reserve requirement in the New York Control Area is stepped, i.e., for the first 200 MW, the system pays a penalty price of 50 \$/MWh, for the next 200 MW, the system pays 100 \$/MWh, and for the rest, the system pays 200 \$/MWh [43]-[44]. The NYISO operator may acquire additional reserve in real-time at any quantity or price point [44].

3.7 Independent System Operator of New England (ISO-NE)

ISO-NE also utilizes constraint relaxations in their market operations. Specifically, ISO-NE implements penalty prices for reserves, known as “reserve constraint penalty factors.” The constraints for different reserve products have different prices. For example, relaxing the 10-minute non-spinning reserve requirement previously cost 850 \$/MWh, but now costs the system 1,500 \$/MWh. Additionally, the 30-minute operating reserve was priced at 500 \$/MWh, but now costs 1,000 \$/MWh [45].

ISO-NE relaxes other constraints, but provides little detail regarding such practices. In [28], it is stated that the relaxation of transmission constraints occurs in a separate process that includes very high penalties. Furthermore, in [46], ISO-NE discusses the consequences of allowing for constraint relaxations; in the example provided, ISO-NE shows that relaxations on interface limits among the northeastern ISOs allows cheaper generation from other ISOs to be dispatched.

3.8 Pennsylvania Jersey Maryland Interconnection (PJM)

PJM utilizes constraint relaxation practices similar to that of other ISOs, where one set penalty price for each constraint is applied. According to [28], these penalty prices included a cost of 1000 \$/MWh for the power balance constraint, 50,000 \$/MWh for ramping constraints, 5000 \$/MWh for normal and emergency operation constraints, and 1000 \$/MWh for transmission constraints.

In [47], penalty prices have been updated by PJM. This includes the penalty price for primary and synchronized reserves in each region, which is set to 850 \$/MWh because PJM witnessed reserve costs exceeding 800 \$/MWh regularly during peak hours.

Furthermore, PJM states that it has a bid cap of 1000 \$/MWh and a maximum LMP of 2700 \$/MWh.

During previous conference calls with industry participants, PJM indicated a need to analyze the consequences of these relaxations practices. PJM has even indicated that relaxations at times can occur in actual operations due to inadequate procurement of capacity or when operators are not concerned about short-term overloads on particular constraints [37].

3.9 Summary

Reliable and economic deployment of a generation fleet to satisfy demand is a complex problem. ISOs and RTOs solve complex unit commitment and economic dispatch models to determine appropriate resources to deploy at various time stages. Due to the complexity of power systems, several approximations are made within optimization models, including approximations of the transmission network with a linearized formulation known as the DCOPF instead of the more realistic ACOPF formulation. Furthermore, approximations occur in these models by relaxing specific constraints in the model, i.e., the constraint is allowed to be violated based on a predetermined penalty price. By doing so, the ISO/RTO receives several benefits, including the ability to manage prices and clear the market as well as the potential to obtain gains in social welfare (market surplus). This work presented describes the constraint relaxation practices of ISOs in their unit commitment models and analyzes the corresponding consequences resulting from these practices.

4. EFFECT OF CONSTRAINT RELAXATION PRACTICES ON MARKET OUTCOMES

4.1 Introduction

ISOs apply constraint relaxations to several constraints throughout the scheduling process. In this thesis, two test cases have been used to analyze the potential impacts constraint relaxations have on market outcomes. The first test case used is the RTS-96 test case [48]. A day-ahead SCUC is formulated and solved with and without constraint relaxations. The only constraint relaxations applied to the RTS-96 test case study was on line flow limits. The resulting market dispatch solutions were subsequently modified utilizing tools within PSS/E to achieve an AC feasible and $N-1$ reliable dispatch schedule. At this point, a comparison is performed on how the modifications made with the tools within PSS/E affect potential market outcomes. This comparison is performed by calculating the settlements from the market LMPs, which are from the SCUC market model, and the ex-post LMPs after all corrections were made to the market solution, as shown by Figure 4.1.

The second test case used to evaluate constraint relaxations is based upon data provided by PJM. With this test case, a SCUC is solved similar to that used for the RTS-96 test case; however, it is only solved for two separate time periods, an on-peak and off-peak hour and, as before, the test case is solved with and without relaxations. The test case is solved with the original penalty prices used by PJM, which resulted in fewer relaxations, and a set of lower penalty prices. For the PJM study, both the node balance constraints and the line flow limit constraints are relaxed. The resulting dispatches are

corrected for AC and $N-1$ feasibility and a comparison of market settlements is performed based on the market LMPs.

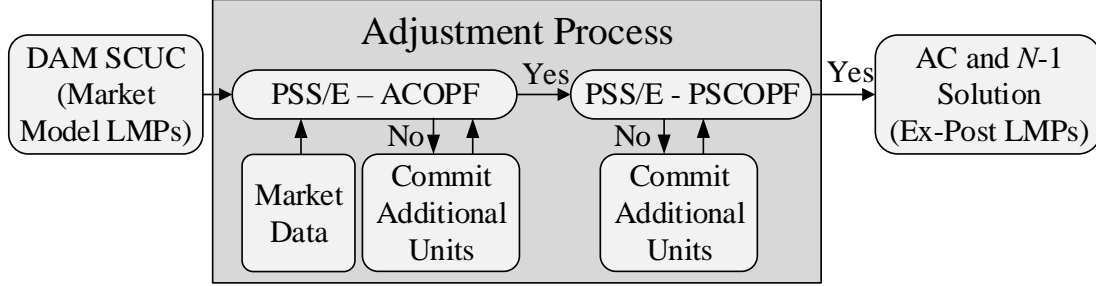


Figure 4.1. Two Stage Process to Achieve AC and $N-1$ Feasible Dispatch Solution.

4.2 Security Constrained Unit Commitment with Key Constraint Relaxations

The SCUC objective (4.1) is to minimize the total system cost while using a linear-piecewise cost curve that requires the segmentation of the power output of the generators, which is exhibited in (4.2)-(4.4). The proxy reserve requirements (4.5)-(4.12) are based on CAISO's rules [22]. They specify that the total reserve must be greater than the largest contingency, (4.5), as well as greater than a combination of load (α) and load met by non-hydro resources (β), (4.6). In [22], CAISO specifies that operating reserves must exceed 5% of the load met by hydro resources and 7% of load met by non-hydro, which translates to $\alpha = 0.05, \beta = 0.02$ in (3.6). The total reserve reflects the spinning and non-spinning reserve, (4.7), and at least half of the operating reserve must come from spinning reserves, (4.8). While these rules are based on CAISO's rules, these reserve requirement rules are similar to the rules used by many system operators.

Additional generator constraints include minimum up- and down-time as well as ramp rate requirements. Note that while the startup and shutdown variables are binary, prior work has proven that with (4.13)-(4.15) and (4.25), it is possible to treat these bina-

ry variables as continuous variables, i.e., (4.23)-(4.24), and still guarantee a binary solution for the startup and shutdown variables [27]. Finally, in the DCOPF formulation, the line flow is calculated with the PTDFs where the total power flow into or out of a bus is represented by a net-injection variable, denoted as P_{nt}^{inj} . The unit commitment could have its line flow constraints violated, accomplished by the addition of the slack variables s_{kt}^{k+} and s_{kt}^{k-} . If these slack variables are anything other than zero, the objective is penalized by the penalty price, PP^K , which is set to \$100/MWh within this formulation. This SCUC is solved with and without line limit constraint relaxations using the RTS-96 test case [27].

$$\min \sum_g \sum_t \sum_i (c_{gi}^{op} P_{git}) + \sum_g \sum_t (c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) + \sum_k \sum_t P^K (s_{kt}^{k+} + s_{kt}^{k-}) \quad (4.1)$$

$$P_{git} = u_{gt} P_{gi}^{Limit} \quad \forall g, i = 1, t \quad (4.2)$$

$$0 \leq P_{git} \leq u_{gt} P_{gi}^{Limit} \quad \forall g, i > 1, t \quad (4.3)$$

$$P_{gt}^{total} = \sum_i P_{git} \quad \forall g, t \quad (4.4)$$

$$P_{gt}^{total} + r_{gt}^{SP} \leq r_t^{req} \quad \forall g, t \quad (4.5)$$

$$r_t^{req} \geq \alpha \sum_g P_{gt}^{total} + \beta \sum_{g \in H(g)=0} P_{gt}^{total} \quad \forall g, t \quad (4.6)$$

$$r_t^{req} \leq \sum_g (r_{gt}^{SP} + r_{gt}^{NS}) \quad \forall t \quad (4.7)$$

$$0.5 r_t^{req} \leq \sum_g r_{gt}^{SP} \quad \forall t \quad (4.8)$$

$$0 \leq r_{gt}^{SP} \leq P_g^{max} - P_{gt}^{total} \quad \forall g, t \quad (4.9)$$

$$r_{gt}^{SP} \leq R_g^{10} u_{gt} \quad \forall g, t \quad (4.10)$$

$$0 \leq r_{gt}^{NS} \leq P_g^{max} (1 - u_{gt}) \quad \forall FS_g = 1, g, t \quad (4.11)$$

$$r_{gt}^{NS} \leq R_g^{10} (1 - u_{gt}) \quad \forall FS_g = 1, g, t \quad (4.12)$$

$$v_{gt} - w_{gt} = u_{gt} - u_{gt-1} \quad \forall g, t \quad (4.13)$$

$$\sum_{s=t-UT_g+1}^t v_{gs+T} + \sum_{s=t-UT_g+1}^t v_{gs} \leq u_{gt} \quad \forall g, t \quad (4.14)$$

$$\sum_{s=t-DT_g+1}^t w_{gs+T} + \sum_{s=t-UT_g+1}^t w_{gs} \leq 1 - u_{gt} \quad \forall g, t \quad (4.15)$$

$$u_{gt-1} R_g^{HR} + v_{gt} P_g^{max} \geq P_{gt}^{total} - P_{gt-1}^{total} \quad \forall g, t \quad (4.16)$$

$$u_{gt} R_g^{HR} + w_{gt} P_g^{max} \geq P_{gt-1}^{total} - P_{gt}^{total} \quad \forall g, t \quad (4.17)$$

$$-P_{nt}^{inj} + \sum_{g \in g(n)} P_{gt}^{total} = d_{nt} \quad \forall n, t \quad (4.18)$$

$$\sum_n P_{nt}^{inj} PTDF_{nk}^{REF} \leq P_k^{max} + s_{kt}^{k+} \quad \forall k, t \quad (4.19)$$

$$-P_k^{max} - s_{kt}^{k-} \leq \sum_n P_{nt}^{inj} PTDF_{nk}^{REF} \quad \forall k, t \quad (4.20)$$

$$\sum_n P_{nt}^{inj} = 0 \quad \forall t \quad (4.21)$$

$$0 \leq v_{gt} \leq 1 \quad \forall g, t \quad (4.22)$$

$$0 \leq w_{gt} \leq 1 \quad \forall g, t \quad (4.23)$$

$$s_{kt}^{k+}, s_{kt}^{k-} \geq 0 \quad \forall n, k, t \quad (4.24)$$

$$u_{gt} \in \{0, 1\} \quad \forall g, t \quad (4.25)$$

4.3 RTS-96 Test Case

A modified version of the RTS-96 test case [27] was used to solve the SCUC unit commitment with line thermal limit relaxations. These modifications include reducing the transmission thermal limits by ten percent without including the HVDC line. Furthermore, for the purposes of this simulation, the load for the peak day was increased by ten percent as well. These actions were taken to increase the number of relaxations the SCUC market model obtained with relaxations.

After the initial SCUC was solved with and without relaxations, these market dispatch solutions were corrected for AC and $N-1$ feasibility. Part of this requirement was to ensure that the voltage deviated no more than $\pm 5\%$ of voltage rating.

4.4 PJM Test Case

Using a similar formulation, a SCUC is solved for an on- and off-peak hour, based on a 15,000 bus test case of the PJM system including actual market data from various operating days. Areas outside PJM were included to accurately account for the tie-line flows. In total, there were over 20,000 lines that appeared in the PJM data set, but ratings were only enforced for lines at or above 138kV. While PJM relaxes many different constraints within their market model, the focus is on relaxation of line limits and node balance constraints. These relaxations were penalized in the model with two sets of penalty prices: i) with the original PJM penalty prices of 1000 \$/MWh and 2700 \$/MWh and ii) with a lower set of 100 \$/MWh and 250 \$/MWh for the line limits and node balance constraints, respectively. Finally, the reserve requirements are modified to resemble those of PJM [49]. The reserve requirements include acquiring total reserve (spinning and non-spinning reserve), which must be at least 150% of the single largest generator contingency. At least half of the total reserve must be spinning reserve and the total spinning reserve must be greater than the largest generator. The other reserve requirements are similar to those in the previous formulation, which include (4.10)-(4.12).

4.5 Correction Process to Attain AC and $N-1$ Feasibility

To attain a base-case AC feasible solution that has no voltage or transmission violations, the PSS/E optimal power flow (OPF) package was used. Market dispatch solutions with and without constraint relaxations are the initial starting point for the AC power flow, which utilizes network controls, such as switchable shunts and transformers' tap settings. In some peak load cases, the adjustment of network controls is not sufficient and, thus, additional units must be committed in order to eliminate large reactive power mismatches.

The approximations incorporated within the market model were corrected by using PSS/E's ACOPF. Using an ACOPF, which assimilates market data and minimizes cost while utilizing shunts and taps controls, ensured that AC related quantities, such as reactive current flow, losses, and voltage limits, were incorporated in the new base-case AC solution. All violations of any defined limits were removed. This process is the first step of the adjustment process in Figure 4.1.

The new AC dispatch solutions provided a feasible base-case solution with no violations. However, $N-1$ contingency analysis revealed that the system was susceptible to various voltage and flow violations following certain contingencies. Additional corrections to AC dispatch solutions were required in order to achieve an $N-1$ reliable solution.

To implement these preventive actions, the following control options were used: switchable shunts, transformers' tap setting adjustments, dispatched generators' active and reactive power output, and committing offline generators. An AC $N-1$ contingency analysis was performed to identify the most severe contingencies that needed to be considered in the preventive correction process. Post-contingency violations were subse-

quently removed using the previously stated control actions; post-contingency limits for voltages were set to $\pm 5\%$ deviation from rated values for the RTS-96 test case and $\pm 20\%$ for the PJM test case. In both cases, line flows were permitted to exceed their thermal ratings by 25%. Contingency analysis was performed again to confirm the effectiveness of the corrective actions and ensure that other contingencies had not been negatively affected. This iterative process was automated throughout this work using the built-in preventive security constrained OPF (PSCOPF) feature in PSS/E. Using PSCOPF also ensured consistency in identifying preventive corrective actions [50]. The result of this process was the achievement of not only AC feasible, but also $N-1$ reliable dispatch solutions and is the final step in Figure 4.1. The correction process described in this section was performed by fellow Ph.D. student Ahmed Salloum.

4.6 Market Implications

To demonstrate the impact of constraint relaxation practices, the deterministic unit commitment program was solved with and without relaxations. The mipgap used to solve these unit commitment programs was set to 1%. Two distinct test cases (RTS-96 and PJM) were used to evaluate the possible market impacts of these relaxation practices.

4.6.1 RTS-96 Test Case Results

The first test case used was the RTS-96 test case, which was solved twice based on (4.1)-(4.25): once without relaxations (SCUC) and once with relaxations (SCUC-CR). The relaxed transmission limits produced from this program are given in Table 4.1.

The dispatch solutions produced by the SCUC and SCUC-CR solutions are neither AC feasible nor $N-1$ reliable. After correcting both of these dispatch solutions to attain AC feasibility and $N-1$ reliability, system settlements were calculated with the market model LMPs (i.e., the LMPs that would come out of the market model and correspond to the approximate solution that is neither $N-1$ feasible nor AC feasible) and then again with the final dispatch solution LMPs (i.e., the marginal cost to deliver one MW after all post-market corrections are established, which reflects ex-post LMP pricing [51]). Table 4.2 presents these three sets of solutions for both cases with and without constraint relaxations; the original market SCUC solutions are presented along with the $N-1$ corrected solutions, which are both AC feasible and $N-1$ reliable.

Table 4.1. Relaxed Transmission Line Limits Produced by SCUC-CR.

Line	Time Period Relaxed	Amount Above Rating (MW)	Percentage (above rating)
25	22	9.96	3.2%
65	7	32.21	10.3%
65	23	25.98	8.3%
104	7	14.18	4.5%
104	8	15.85	5.0%
104	23	16.92	5.4%

The system settlements, particularly for generators, were determined for these solutions and can be seen in Table 4.2. There is a slight difference in the total system cost in the SCUC and SCUC-CR solutions. Note that the total system cost for the SCUC-CR solution includes the penalty cost for relaxing transmission limit constraints. Since the solution from SCUC-CR was able to produce constraint relaxations, it produced a cheaper solution compared to the SCUC solution with no relaxations. These results emulated those produced from market models employed today.

The market solution for the SCUC had a resulting optimality gap of 0.27%; the SCUC solution's lower bound is higher than the best incumbent solution obtained for the SCUC-CR market solution, whose resulting optimality gap was 0.1%. While the SCUC-CR optimal solution must be as cheap, if not cheaper, than the non-relaxed solution, there is no guarantee that the incumbent solution will be cheaper if the problems are not solved to optimality. Even though the market models are not solved to optimality today due to time restrictions, it is still expected that the relaxed solution has a lower market cost. However, it is important to keep in mind that such a solution involves relaxations, which are considered to be actual violations. Therefore, the emphasis needs to be placed on the actual cost to operate an AC feasible and $N-1$ reliable system, which are the costs after all of the corrections have been made.

Comparing the two AC feasible and $N-1$ reliable solutions, the solution with relaxations had a lower system cost than the solution without relaxations. The difference in total cost was approximately \$245,000, or roughly 5%, over the entire day, much larger than the difference in the market solution costs of 0.3%. The final difference in costs (5%) between the two solutions is not due to just the relaxations but is obviously also dependent on the corrections made within the adjustment phase. While the adjustment phase itself is imprecise (i.e., due to the complexity, an optimal adjustment is not determined), this process replicates industry practices and it is important to capture whether the practice of constraint relaxations increases the reliance on out-of-market corrections. This issue is left for further review in the discussion section of Chapter 4.6.3.

The day-ahead SCUC solution (without relaxations) exhibited a cost increase of \$700,000 between the original market solution and the final corrected solution that is AC

feasible and $N-1$ reliable. The day-ahead SCUC-CR solution (with relaxations) exhibited a lower increase in cost between the original market solution and the final AC feasible and $N-1$ reliable solution, a cost of only \$490,000. This result is somewhat counterintuitive; it may be expected that the solution with relaxed constraints would cost more to obtain a proper AC feasible and $N-1$ solution. However, this result intriguingly shows that this is not always the case. When there are two infeasible solutions, it is not possible to guarantee which solution will cost less to correct to achieve feasibility. A solution with more overall relaxations may very well be cheaper once feasibility is achieved. This result also then translates to the SCUC-CR solution having a lower overall cost, meaning that this practice improves the overall social welfare even after all corrections have been made. While this is only one result, it roughly confirms one argument in support of constraint relaxations: it is questionable to impose such strict requirements when the model itself is a rough approximation.

With all the corrections made to both dispatch solutions, generator profit decreased as expected. When utilizing the ex-post LMPs that reflect the implemented out-of-market changes made to guarantee AC feasibility and $N-1$ reliability (during the day-ahead scheduling process), the generators were able to make a profit with the final SCUC dispatch solution. However, the final solution for the SCUC-CR indicated that generators would incur a loss over the entire 24-hour time horizon. Note this profit is determined by LMP payments alone and does not include the subsequent uplift payments, whose calculation is similar to that in [36]. This would only occur if there were no deviation during real-time operations. Today, operators post day-ahead market results based upon the orig-

inal LMPs from the day-ahead market model. In this case, both dispatch solutions exhibited generators making a profit over the entire operating day.

Table 4.2. Market Results in (\$k for tested peak day) for SCUC-CR and SCUC.

SCUC-CR market solution and resulting N-1 corrected solution				
	Total Cost	Gen. Revenue	Uplift	Gen. Profit + Uplift
Market SCUC Solution	4,082	11,457	297	7,684
N-1 Corrected (Market Model LMPs)	4,557	11,682	564	7,688
N-1 Corrected (Ex-Post LMPs)	4,557	4,456	2,071	1,969
SCUC market solution and resulting N-1 corrected solution				
Market SCUC Solution	4,095	11,518	303	7,726
N-1 Corrected (Market Model LMPs)	4,803	11,734	799	7,730
N-1 Corrected (Ex-Post LMPs)	4,803	5,391	2,103	2,691

If the day-ahead market settlements were based on LMPs after the out-of-market corrections are performed during the day-ahead scheduling process (analogous to ex-post real-time pricing), then the generator revenue and profit would be much lower (compared to market model LMPs) for both cases with and without constraint relaxations. The uplift payments are also much higher with ex-post pricing. The results provide a mechanism to analyze how market settlements are impacted when constraints are relaxed within the market model but are later corrected outside of the market (auction) engine by operators. These results first show that the main impacts on settlements are not primarily the constraint relaxations that occur but the inaccuracies within the market models associated with not having an ACOPF or an explicit representation of all contingencies. This can be observed since both results with and without constraint relaxation have substantially lower generator profits after the correction phase; note, however, that such results do not guarantee this as a general outcome. Nevertheless, there is still a difference between the

solutions that employ constraints relaxations and those that do not. Furthermore, the practice of constraint relaxations influences system operating costs, as shown in Table 4.2.

4.6.2 PJM Test Case Results

Extending the analysis performed on the RTS-96 test case, another test case was constructed from data provided by PJM. A single period SCUC model, with and without relaxations, was solved for an off-peak and on-peak period. The market solutions were then modified to achieve AC and $N-1$ feasibility. Additionally, SCUC-CR was solved with line limit relaxations and node balance relaxations for two sets of penalty prices: i) with lower prices of 100 \$/MWh and 250 \$/MWh and ii) with PJM's original penalty prices of 1000 \$/MWh and 2700 \$/MWh for line limit and nodal relaxations respectively. Note that when a nodal relaxation occurs in the model, the dual variable (LMP) is limited by the penalty price. In the SCUC model solution, no relaxations were allowed and, thus, the highest LMPs exhibited in the system were \$1473 and \$2754 for the off- and on-peak hours, respectively.

For the off-peak hour, the SCUC-CR solution, with lower penalty prices resulted in 57 MW of nodal relaxations, less than 0.1% of demand. The total line limit relaxations for the off-peak hour were 743 MW on nine lines. Furthermore, when solving with the SCUC-CR model for the off-peak hour, the model chose not to relax any constraints with the original penalty prices.

For the on-peak hour, the SCUC-CR with lower penalty prices chose a greater amount of nodal relaxations, approximately 5400 MW. These relaxations occurred but were not limited to the areas controlled by PJM (i.e., some relaxations occurred outside

of PJM's territory due to model approximations). These nodal relaxations represent 3.5% of the total load for PJM's system and the outside areas that were also represented during the on-peak hour. Furthermore, due to these nodal relaxations, the LMP is limited only to \$250 at several nodes, thereby controlling prices. The market chose to relax eight lines for the line thermal limit relaxations, but only overloaded these lines by a total of 490 MW. Unlike the RTS-96 test case results, the initial gap between the market solutions is much greater when comparing the SCUC and SCUC-CR solutions with the lowered penalty prices. The difference in total system cost between the initial market solutions for off- and on-peak hours are 3.9% and 8.3%, respectively, with the SCUC-CR solutions being cheaper. The difference in total system costs between the final AC and *N-1* feasible solutions for the off- and on-peak hours are 10% and 2.5%, respectively, this time with the SCUC solutions being cheaper. For market solutions with relaxations, the off- and on-peak hours required changes to the dispatch solution to the point that the total system cost changed dramatically. While the penalty prices are lower than what PJM employs, these results demonstrate what can happen to the costs and market settlements once an infeasible solution with relaxations is corrected by the operator.

When the on-peak hour is solved with the original penalty prices (2700 \$/MWh for node and 1000 \$/MWh for line relaxations), the SCUC-CR solution had a relaxation of 340 MW total on seven lines. There were no nodal relaxations because the highest LMP obtained only reached \$905 because the model was able to find a cheaper cost solution with only line relaxations. As expected, the relaxed market solutions produce lower overall costs than the market solutions without relaxations. The initial SCUC-CR market solution only has a 1.3% difference with the cost of the initial market SCUC solution.

With the original penalty prices, few relaxations occur, and the relaxations that did occur were not due to feasibility requirements, because a solution was obtainable without relaxations in this test case, but rather to the economic benefit of relaxing the constraint for the specified penalty price. Finally, the overall total cost after obtaining AC feasibility and $N-1$ reliability is higher for the relaxed market solution compared to the market solution without relaxations. While such a result is not guaranteed, a solution with relaxations is expected to cost more in the end, as the relaxed solution is likely to rely more on costly out-of-market corrections by the operator. Additional results regarding market settlements can be seen in Table 4.3 and in Figure 4.2, which further demonstrate how constraint relaxation practices can substantially influence market settlements.

When comparing market solutions, for the on-peak hour between the two SCUC-CR models with low penalty prices and the original penalty prices, the initial market solution corresponding to the low penalty price model was approximately 7% cheaper than the SCUC-CR with the original penalty prices. The low penalty price model has a penalty on the node balance constraint of 250 \$/MWh, which causes this result. While the lower penalty price market-based solution will have a cheaper market-based cost (higher market surplus), both solutions must be corrected to achieve an $N-1$ AC feasible solution. After correcting these dispatch solutions to achieve AC and $N-1$ feasibility, the final cost for the SCUC-CR with low penalties was cheaper only by 0.9%. There were far more corrections required for the SCUC-CR solution with low penalties due to the high number of nodal relaxations (5400 MW) as well as 490 MW of line relaxations. In comparison, the SCUC-CR solution with the original penalty prices had no nodal relaxations and 340 MW of line relaxations. Such a result demonstrates that while the penalty prices may be

substantially lower to produce a market solution that is more efficient, the actual efficiency gains may still be modest; solutions with more relaxations are naturally expected to require more corrections.

The two market solutions are also distinguishable as the low penalty price model substantially limits the LMPs to 250 \$/MWh since the LMP cap is much lower, so there is an obvious difference in the settlements. The results also show that there is a much wider range of LMPs across the system. For instance, for the on-peak hour, the SCUC solution without relaxations has a standard deviation for the LMPs above 100, the SCUC-CR with the original penalties has a standard deviation at roughly 70, and the low penalty case has a standard deviation at about 15. The congestion rent in the low penalty case is also half of the congestion rent for the original penalty case. Another important result is that the uplift payments are also much higher for the case with a low penalty price; lowering the price cap then reduces profits and more generators need to receive a side payment (uplift) as a result. Thus, the original prices result in much higher settlements, which include generator revenue, generator profit, congestion rent, and load payment. The results in Figure 4.2 and Table 4.3 illustrate how the chosen prices influence settlements dramatically while the costs to operate the system do not experience such a wide variation between the results. Constraint relaxation is thus shown to be very influential in settlements as well as imposing price control.

It should be noted that the difference in total system cost between the market solution and its corresponding AC and *N-1* feasible solution is likely greater than what would be expected. Commercial-grade MMS are tailored to the system to account for system specific limitations to improve the approximation of the SCUC model (e.g., the inclusion

of reliability must run units or nomograms). Thus, the market solution should be closer to the final solution than that reported within this work. Nevertheless, the comparative results with the same SCUC model except for relaxations demonstrate that constraint relaxations can substantially impact market settlements.

Note that to obtain AC feasibility and $N-1$ reliability, additional units are only committed after all other control options have been exhausted. For the off-peak hour, the PJM SCUC market results required an additional 14 generators to achieve AC and $N-1$ feasibility whereas the PJM SCUC-CR market results with low penalties required 28 additional generators. For the on-peak hour to achieve AC and $N-1$ feasibility, the PJM SCUC market results required 22 generators to be committed and PJM SCUC-CR with low penalties required 74 generators. For the latter results where the relaxed case needed what seemed to be an abnormally high amount of additional generators, this amount only accounted for an additional 7% of generation. Regarding the PJM SCUC-CR with original penalties, this market solution required an additional 62 generators to be committed to attain AC and $N-1$ feasibility.

As for generator revenue, every scenario exhibited an increase when comparing the initial market solution and the final AC and $N-1$ feasible solution based upon market LMPs; this is due to the fact that additional units are committed while the market settlements for generators committed based on the market solution are maintained. The uplift payments also increase as well. The highest increase is exhibited for the on-peak hour when the market solution was initially relaxed with the lower penalty prices. The greatest increase in profit occurred for the on-peak hour when no relaxations were allowed. Both relaxed market solutions result in higher costs in the end than the solution without relaxa-

tions; however, the generation revenue, generation profit, and load payments are all lower for the relaxed solutions. This is, in part, a result of the fact that relaxations cap market clearing prices. These results can be viewed in Table 4.3 as well as in Figure 4.2.

Table 4.3. Market Results for PJM Market and Resulting *N*-1 Final Feasible Solutions
(\$k per hour tested).

	Time Period	Total Cost	Gen. Revenue	Uplift	Gen. Prof- it + Uplift
SCUC (no relaxations)					
Market	Off	5,720	10,601	948	5,829
	On	16,649	42,255	63	25,669
<i>N</i>-1 Feasible	Off	10,499	11,852	5,547	6,899
	On	22,529	44,665	4,910	27,045
SCUC-CR low penalty prices					
Market	Off	5,499	10,602	43	5,235
	On	15,329	31,781	96	17,961
<i>N</i>-1 Feasible	Off	11,620	11,452	5,939	5,771
	On	23,106	35,147	6,700	18,740
SCUC-CR PJM original penalty prices					
Market	On	16,431	40,194	23	23,819
<i>N</i>-1 Feasible	On	23,315	42,695	4,879	24,259

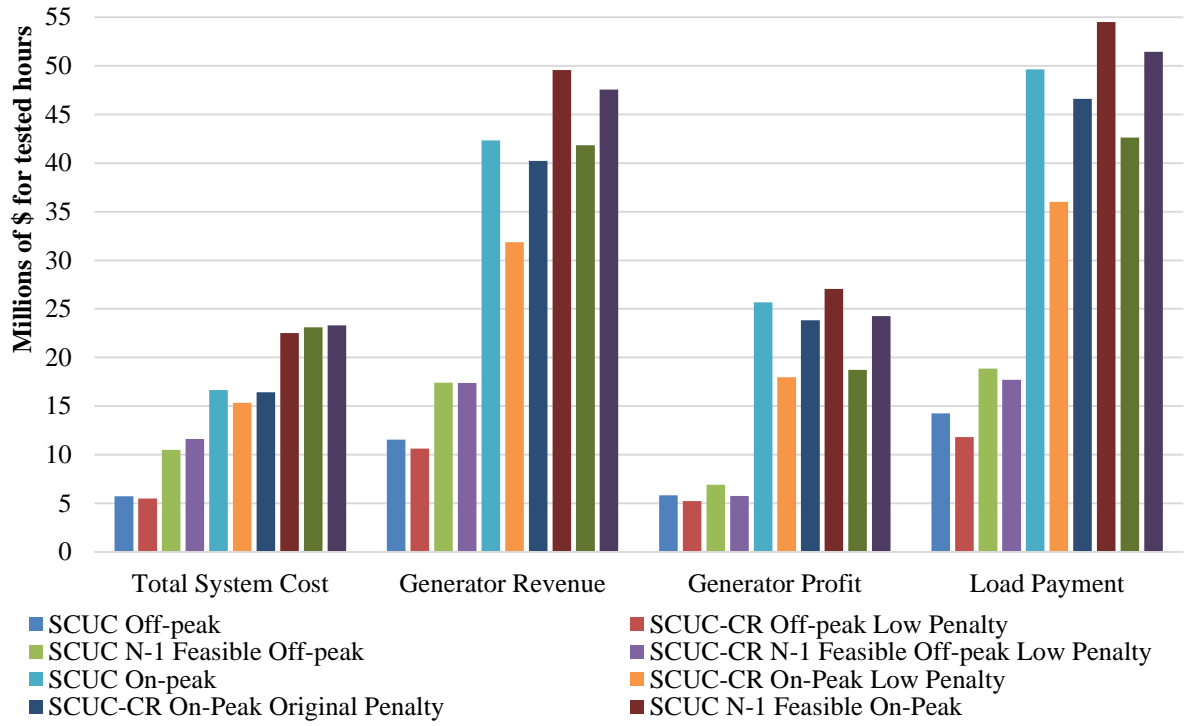


Figure 4.2. System Settlement Results for Both On- and Off-Peak Hours, with and without Relaxations; Generator Revenue, Generator Profit, and Load Payment Include the Uplift Payments.

4.6.3 Discussion

When the market model involves constraint relaxations, the optimal solution to the SCUC-CR model is at least as good, if not better, than the optimal solution of the SCUC model without relaxations. However, the simulations conducted for this study demonstrate that it is not possible to conclude what method will produce a lower cost at the final stage of the process after each solution is modified to be AC feasible and $N-1$ reliable. While the SCUC-CR solution is considered to be infeasible due to the relaxations, both solutions are infeasible due to the DC approximation and the proxy reserve

requirements that do not guarantee $N-1$. The results show that the final solutions are not just dependent on the solution produced by the market engine but that they are also dependent on the procedures taken to modify the solutions to get reliable solutions. Overall, the results demonstrate that it may not be beneficial to have an overly precise market model since the market model has other approximations embedded in it anyway. One result demonstrates the final cost (\$23,315k) for the PJM market solution with PJM's original relaxation prices that resulted in minimal relaxations is higher than the final cost (\$23,106k) for the PJM market solution with much lower relaxation prices while having many more relaxations in the market solution.

On the other hand, having more relaxations in the market solution can result in more corrections needed outside the market environment. For the PJM on-peak hour, the market solution that contained relaxations required twice as many additional units to be committed during the adjustment process (i.e., taking the market solution and modifying it to obtain an AC feasible, $N-1$ solution). Such adjustments are based on ad-hoc operator influenced modifications, which are not clearly established or published, leaving more ambiguity relative to the overall process, which is not preferred by market participants, especially when the results demonstrate that these practices influence market settlements.

4.7 Conclusions

This chapter included an overview of existing constraint relaxation practices of the ISOs within the United States. SCUC models are formulated with and without relaxations in order to assess the overall impact on market costs and market settlements as a result of constraint relaxations. Results are presented for two test cases: i) an IEEE test

case and ii) a large-scale model of the PJM system with actual market data used in this study. All market SCUC solutions were then modified to attain an AC feasible and $N-1$ reliable solution. The results thus demonstrate whether relaxations within the market engine require additional operator-based costly out-of-market corrections to occur, which can substantially impact not only market efficiency but also market settlements.

It was expected that after applying these corrections, the dispatch schedule, which allowed for constraint relaxations, would result in a higher cost schedule because more costly out-of-market corrective actions would be anticipated to be necessary. In the RTS-96 test case, that did not occur and the final feasible dispatch solution whose market solution contained relaxations had a lower total cost than the final dispatch solution whose market solution did not contain relaxations. As for the PJM test case, the dispatch results that initially contained constraint relaxations did need more adjustments to attain $N-1$ reliability and, as expected, the total cost solution for the dispatch without relaxations had a lower total cost in the end when comparing $N-1$ reliable dispatch solutions. For the PJM results, not only are the final costs higher, but the generation revenue, generation profit, and load payment are all lower. Thus, the sacrifice for price control seems to be higher overall system costs, lower profits for generators, and lower payments for the load.

Even though market participants have previously agreed to such practices, one aspect that is generally not preferred is the lack of transparency. While the structure of market models and settlement schemes are widely known, the process operators take to correct solutions produced by the market engine that are not feasible is far less transparent. While there is no guarantee, intuitively, the more relaxations that occur, the more corrections are expected in this adjustment phase leading to less transparency.

5. EFFECT OF RESERVE RELAXATIONS ON $N-1$ SECURITY

5.1 Introduction

Not all operating and reliability criteria can be explicitly modeled in the market and will require the proposed day-ahead market model's solution from the MMS to be adjusted, necessitating an additional adjustment or post-processing phase to correct for the approximations and inaccuracies inherent in market solutions. For example, the market solution must be altered to meet $N-1$ reliability criteria, a NERC standard [25]-[26] stating that the system must be able to withstand the loss of a single bulk element (transmission line or generator). The effect of constraint relaxations on market outcomes [52] as well as system security performance [53] due to line and nodal constraint relaxations in the market solution has been investigated in previous work. In [54], the effects of pre- and post-contingency transmission line relaxations were investigated and reserve deliverability with renewable penetration was examined in [55].

ISOs and RTOs differ in their market practices regarding constraint relaxations, outlined in Chapter 3. Some utilize a fixed-price penalty price scheme in their market models, but others prefer a staircase penalty price function [32]. Also as stated previously in Chapter 3.6, NYISO utilizes a staircase function for its reserve requirement penalty price scheme. In this chapter, both of these penalty price schemes are tested for constraint relaxations that are similar to reserve requirement constraints. Note that reserve requirements are proxy constraints used in the market model that attempt to attain an $N-1$ secure solution. However, these constraints are approximations and do not explicitly model $N-1$ contingency scenarios and therefore cannot guarantee the $N-1$ security requirement. This

is one reason why constraint relaxations are used in the market model. Enabling constraint relaxations is a method of coping with this issue. Furthermore, there is the notion that some constraints should be modeled as soft constraints because they are approximations. For example, the reserve requirement constraint is an approximation and at times could lead to model infeasibilities. In this work, the effect that reserve relaxations have on market outcomes and potential $N-1$ violations will be examined.

5.2 Procedure

To investigate the potential impact of reserve relaxations on system security and market outcomes, the three area RTS-96 test case [48] was modified to include a 10% reduction in capacity limits for both normal operations and emergency ratings for all 120 transmission lines and transformers. In all other respects, the test case utilized the same data for all 96 generators located across 73 buses, 51 of which included aggregated load.

The RTS-96 test case provides an entire year of load data. To choose representative days, the k-means clustering algorithm in MATLAB [56] was used. This algorithm used the season, the total load, the day type, and the hourly change in load to allocate each day into four different clusters. With this algorithm, the load data was separated into four different clusters and sixteen days were selected from each cluster for a total of 64 days tested across all four clusters.

5.2.1 SCUC without Reserve Relaxations

A traditional SCUC formulation without relaxations was used for comparison with the relaxed cases. The SCUC formulation is given in (5.1)-(5.25). The objective (1) minimizes total system cost, including the procurement of operating (contingency) reserves. In (5.2)-(5.6), generator operating constraints are represented, including generator capacity and ramping constraints. The facet defining constraints [57]-[58] regarding unit status, start-up, and shutdown variables are presented in (5.7)-(5.9). As a result, from (5.23)-(5.25), only the status variable, u_{gt} , must be binary while the start-up and shutdown, v_{gt} and w_{gt} respectively, can be continuous variables.

The reserve requirements are represented in (5.10)-(5.17). Taking a more conservative approach, the SCUC is required to acquire reserves greater than or equal to 120% of the single largest generator contingency (5.10) and is a modification of CAISO's rule [22]. However, this modification is less than PJM's rule of 150% [49]. In addition, CAISO's rule that specifies that the total reserve acquired must be greater than a combination of load (α) and load met by non-hydro resources (β) is still applied by (5.11). CAISO specifies that operating reserves must exceed 5% of the load met by hydro resources and 7% of load met by non-hydro, which translates to $\alpha = 0.05$, $\beta = 0.02$ in (5.11). From (5.12), the total reserve is reflected as spinning and non-spinning reserve and from (5.13) the total reserve must obtain at least half from spinning reserve, while (5.14)-(5.17) represent the limits for the spinning and non-spinning reserve acquired.

Finally, the DCOPF formulation is used to represent the network in (5.18)-(5.20). Line flow is calculated using a power transfer distribution factor (PTDF) formulation and

a net-injection variable, denoted as P_{nt}^{inj} , representing the total power flow into or out of a bus for a given period t . Note that in (5.21), line outage distribution factors (LODFs) are used to include transmission contingencies in the SCUC formulation [13], [59]. As a result, the dispatch chosen by the SCUC is $N-1$ secure for transmission line contingencies.

$$\begin{aligned} \text{Minimize } & \sum_g \sum_t \sum_i (c_{gi}^{op} P_{git}) + \sum_g \sum_t (c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) \\ & + \sum_g \sum_t (0.25 c_{gl}^{op} r_{gt}^{sp} + 0.05 c_{gl}^{op} r_{gt}^{NS}) \end{aligned} \quad (5.1)$$

$$u_{gt} P_g^{min} \leq P_{gt} \leq u_{gt} P_g^{max} \quad \forall g, i = 1, t \quad (5.2)$$

$$0 \leq P_{git} \leq u_{gt} P_{gi}^{limit} \quad \forall g, i, t \quad (5.3)$$

$$P_{gt} = \sum_i P_{git} \quad \forall g, t \quad (5.4)$$

$$u_{gt-1} R_g^{HR} + v_{gt} R_g^{SU} \geq P_{gt} - P_{gt-1} \quad \forall g, t \quad (5.5)$$

$$u_{gt} R_g^{HR} + w_{gt} R_g^{SD} \geq P_{gt-1} - P_{gt} \quad \forall g, t \quad (5.6)$$

$$v_{gt} - w_{gt} = u_{gt} - u_{gt-1} \quad \forall g, t \quad (5.7)$$

$$\sum_{s=t-UT_g+1}^t v_{gs+T} + \sum_{s=t-UT_g+1}^t v_{gs} \leq u_{gt} \quad \forall g, t \quad (5.8)$$

$$\sum_{s=t-DT_g+1}^t w_{gs+T} + \sum_{s=t-UT_g+1}^t w_{gs} \leq 1 - u_{gt} \quad \forall g, t \quad (5.9)$$

$$1.2 P_{gt} + r_{gt}^{SP} \leq r_t^{req} \quad \forall g, t \quad (5.10)$$

$$r_t^{req} \geq \alpha \sum_g P_{gt} + \beta \sum_{g \in H(g)=0} P_{gt} \quad \forall g, t \quad (5.11)$$

$$r_t^{req} \leq \sum_g (r_{gt}^{SP} + r_{gt}^{NS}) \quad \forall t \quad (5.12)$$

$$0.5 r_t^{req} \leq \sum_g r_{gt}^{SP} \quad \forall t \quad (5.13)$$

$$0 \leq r_{gt}^{SP} \leq P_g^{max} - P_{gt} \quad \forall g, t \quad (5.14)$$

$$r_{gt}^{SP} \leq R_g^{10} u_{gt} \quad \forall g, t \quad (5.15)$$

$$0 \leq r_{gt}^{NS} \leq P_g^{max} (1 - u_{gt}) \quad \forall FS_g = 1, g, t \quad (5.16)$$

$$r_{gt}^{NS} \leq R_g^{10}(1 - u_{gt}) \quad \forall FS_g = 1, g, t \quad (5.17)$$

$$-P_{nt}^{inj} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (5.18)$$

$$-P_k^{max} \leq \sum_n P_{nt}^{inj} PTDF_{nk}^{REF} \leq P_k^{max} \quad \forall k, t \quad (5.19)$$

$$\sum_n P_{nt}^{inj} = 0 \quad \forall t \quad (5.20)$$

$$-P_k^{max,C} \leq \sum_n P_{nt}^{inj} PTDF_{nk}^{REF} + LODF_{kz} \sum_n P_{nt}^{inj} PTDF_{nz}^{REF} \leq P_k^{max,C} \quad \forall k, z, t \quad (5.21)$$

$$0 \leq v_{gt} \leq 1 \quad \forall g, t \quad (5.22)$$

$$0 \leq w_{gt} \leq 1 \quad \forall g, t \quad (5.23)$$

$$u_{gt} \in \{0,1\} \quad \forall g, t \quad (5.24)$$

5.2.2 SCUC Reformulation to Include Reserve Relaxations

Two different reserve relaxation schemes, a fixed-price scheme and staircase curve price scheme are examined. Similar to [60], spinning reserve was assumed to be 25% of the last operating cost segment and non-spinning reserve was assumed to be 5% of the last operating cost segment, such that the non-spinning price would be less than the spinning reserve price. As a result, the highest price for spinning reserve was approximately 25 \$/MW, while non-spinning reserve was only offered at approximately 10 \$/MW. Including reserve relaxations in the SCUC means that the objective (5.1), reserve requirement for total reserves (5.12) and the reserve requirement that requires half come from spinning reserve (5.13) must be modified.

For fixed-price relaxations, the following modifications needed for (5.1) and (5.12)-(5.13) are shown in (5.25)-(5.28). The prices for relaxing spinning and non-spinning reserves are listed in Table 5.1 and Table 5.2 below.

$$\begin{aligned} \text{Minimize } & \sum_g \sum_t \sum_i (c_{gi}^{op} P_{git}) + \sum_g \sum_t (c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) \\ & + \sum_g \sum_t (0.25 c_{gi}^{op} r_{gt}^{sp} + 0.05 c_{gi}^{op} r_{gt}^{NS}) + \sum_t (c^{SP} s_t^{SP} + c^{NS} s_t^{NS}) \end{aligned} \quad (5.25)$$

$$r_t^{req} \leq \sum_g (r_{gt}^{SP} + r_{gt}^{NS}) + s_t^{SP} + s_t^{NS} \quad \forall t \quad (5.26)$$

$$0.5 r_t^{req} \leq \sum_g r_{gt}^{SP} + s_t^{SP} \quad \forall t \quad (5.27)$$

$$s_t^{SP}, s_t^{NS} \geq 0 \quad \forall t \quad (5.28)$$

For staircase curve price relaxations, the following modifications needed for (5.1) and (5.12)-(5.13) are shown in (5.29)-(5.34). The index x represents the number of steps, which is assumed to be three, and the price for each step monotonically increases from the previous step. The prices for relaxing spinning and non-spinning reserves are listed in Table 5.1 and Table 5.2 below. Note that for the staircase relaxation scheme, a fourth iteration was solved, but the solution did not produce any relaxations and therefore its results were not reported.

$$\begin{aligned} \text{Minimize } & \sum_g \sum_t \sum_i (c_{gi}^{op} P_{git}) + \sum_g \sum_t (c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt}) \\ & + \sum_g \sum_t (0.25 c_{gi}^{op} r_{gt}^{sp} + 0.05 c_{gi}^{op} r_{gt}^{NS}) + \sum_t \sum_x (c_q^{SP} s_{tx}^{SP} + c_q^{NS} s_{tx}^{NS}) \end{aligned} \quad (5.29)$$

$$r_t^{req} \leq \sum_g (r_{gt}^{SP} + r_{gt}^{NS}) + \sum_x (s_{tx}^{SP} + s_{tx}^{NS}) \quad \forall t \quad (5.30)$$

$$0.5 r_t^{req} \leq \sum_g r_{gt}^{SP} + \sum_x s_{tx}^{SP} \quad \forall t \quad (5.31)$$

$$0 \leq s_{tx}^{SP}, s_{tx}^{NS} \leq 2 \quad \forall x = 1, t \quad (5.32)$$

$$0 \leq s_{tx}^{SP}, s_{tx}^{NS} \leq 5 \quad \forall x = 2, t \quad (5.33)$$

$$s_{tx}^{SP}, s_{tx}^{NS} \geq 0 \quad \forall t \quad (5.34)$$

Table 5.1. Spinning Reserve Relaxation Prices.

Scheme Type		Price 1	Price 2	Price 3	Price 4
Fixed		50 \$/MWh	100 \$/MWh	200 \$/MWh	400 \$/MWh
Staircase-price	Set 1 (2 MW allowed)	50 \$/MWh	100 \$/MWh	200 \$/MWh	N/A
	Set 2 (5 MW allowed)	100 \$/MWh	200 \$/MWh	400 \$/MWh	N/A
	Set 3 (unlimited)	500 \$/MWh	1000 \$/MWh	2000 \$/MWh	N/A

Table 5.2. Non-Spinning Reserve Relaxation Prices.

Scheme Type		Price 1	Price 2	Price 3	Price 4
Fixed-price		40 \$/MWh	80 \$/MWh	200 \$/MWh	400 \$/MWh
Staircase-price	Set 1 (2 MW allowed)	40 \$/MWh	80 \$/MWh	160 \$/MWh	N/A
	Set 2 (5 MW allowed)	80 \$/MWh	160 \$/MWh	320 \$/MWh	N/A
	Set 3 (unlimited)	400 \$/MWh	800 \$/MWh	1600 \$/MWh	N/A

5.3 Contingency Analysis with Acquired Reserves

As part of testing the potential impacts of reserve relaxations, the non-relaxed SCUC, fixed-priced relaxed SCUC, and the staircase relaxed SCUC solutions were tested for $N-1$ violations with a contingency analysis tool (5.35)-(5.42) that only allows acquired reserve from the market solution to alleviate the $N-1$ contingency. This model allows for infinite transmission capability by including the slack variables s_{kt}^+ and s_{kt}^- . However, if either of these variables is greater than zero, the dispatch is not $N-1$ secure. Note the model presented is for generator contingencies and can be easily modified for non-radial transmission line contingencies. However, with the LODFs formulation in the SCUC,

non-radial transmission contingencies have already been taken into account, i.e. the event and the recourse action are taken into account in the market solution.

$$\text{minimize } \sum_k \sum_t s_{kt}^+ + s_{kt}^- \quad (5.35)$$

$$N1_g \bar{u}_{gt} (\bar{P}_{gt} - \overline{R_{gt}^{SP}}) \leq \hat{P}_{gt} \leq N1_g \bar{u}_{gt} (\bar{P}_{gt} + \overline{R_{gt}^{SP}}) \quad \forall g, t \quad (5.36)$$

$$N1_g P_g^{\min} \bar{u}_{gt} \leq \hat{P}_{gt} \leq N1_g P_g^{\max} \bar{u}_{gt} \quad \forall g, t, FS_g = 0 \quad (5.37)$$

$$0 \leq \hat{P}_{gt} \leq N1_g \overline{R_{gt}^{NS}} \quad \forall g, t, FS_g = 1 \quad (5.38)$$

$$-P_k^{\max, C} - s_{kt}^- \leq P_{kt} \leq P_k^{\max, C} + s_{kt}^+ \quad \forall k, t \quad (5.39)$$

$$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall t \quad (5.40)$$

$$\sum_{\forall \in \delta^+(n)} P_{kt} - \sum_{\forall \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (5.41)$$

$$s_{kt}^+, s_{kt}^- \geq 0 \quad \forall k, t \quad (5.42)$$

5.4 Benders' Decomposition

After evaluating the market solutions based on $N-1$ violations (5.35)-(5.42), both relaxed and non-relaxed market solutions are corrected for $N-1$ violations using a Benders' decomposition algorithm similar to [24] and [61], except non-spinning reserve was allowed to participate in mitigating $N-1$ violations. The original dispatch solutions (relaxed and non-relaxed) were all corrected such that no post-contingency violations occurred. After obtaining the $N-1$ secure solutions, market outcomes were compared. Finally, it should be noted that these $N-1$ secure solutions will no longer contain any reserve relaxations.

5.5 Results

The modified RTS-96 test case [48] was solved by using the model presented above without relaxations (non-relaxed), fixed-priced relaxations (fixed-price), and staircase-priced relaxations (staircase). Furthermore, fixed-priced and staircase-priced relaxations cases were solved multiple times with increasing penalty prices, which are given in Table 5.1 and Table 5.2. In all three cases, the reserve rule, (5.10), captured the same amount of total operating reserves (approximately 701GW) summed over all study days, including spinning and non-spinning reserves. With the fixed-price and staircase relaxations, not all of total reserve was truly acquired because the market solution instead chose to acquire an artificial reserve product through the slack variables. Although the reserve required was approximately the same, the amount acquired from the market was less. Results regarding the number of relaxations for both cases (fixed-price and staircase), total system cost from the initial market solutions, $N-1$ security violations, and market outcomes corrected of the $N-1$ secure solutions obtained from utilizing the Benders' decomposition algorithm were compared. All mipgaps for the market SCUC with and without relaxations as well as the Benders' decomposition were set to 0.5%.

The amount of reserve relaxed for each price iteration is given in Table 5.3. From these results, it can be seen that the fixed-price relaxation penalty scheme has more relaxations because the slack variable allows for any amount of reserve to be relaxed at a single set price. On the other hand, the staircase relaxation scheme has less relaxations overall because the first two stairs of relaxations are constrained to be at most 2 and 5 MWh, respectively, and the final stair allows for any amount. As a result, the staircase market solution only exhibits relaxations for the first three sets of prices, as seen in Table 5.1 and

Table 5.2. Of the 64 days tested, not all days exhibited relaxations. For the fixed-price penalty scheme, the number days with relaxations was 28, 17, 13, and 8 with respect to the increasing price sets given in Table 5.1 and Table 5.2. Additionally, for the staircase-price penalty scheme, the days with relaxations were 17, 11, and 10 with respect to the increasing price sets as shown in Table 5.1 and Table 5.2.

Both relaxed solutions (fixed-price and staircase-price) have lower total system costs compared to the non-relaxed solution, which is expected because a SCUC that allows for relaxations has a greater feasible space and, therefore, is able to find a less costly market solution. In Table 5.4 below, the total system cost summed over days with reserve relaxations and the number of days with relaxations of the relaxed (fixed-price and staircase-price) market solutions for each price iteration is shown. Since not all days in the data set had relaxations for the fixed-price and staircase-priced market solutions, only days with relaxations were compared. Furthermore, as the penalty price increased, the number of days with reserve relaxations decreased. For comparison, the non-relaxed market solution is summed separately over the same days of each relaxed solution, which is why there are two entries for the non-relaxed solution. From Table 5.4, it can be seen that the market solution for the non-relaxed case always has a slightly higher cost than both relaxed cases, which is expected because both fixed-priced and staircase market solutions that were relaxed should be no worse off than the non-relaxed solution.

When testing these solutions for $N-1$ violations using (5.36)-(5.43), only the operating reserve acquired was allowed to participate in attempting to mitigate the potential violations from the $N-1$ contingency. In Table 5.5 below, the $N-1$ violations for hours with relaxations are reported for the fixed-priced and staircase-priced relaxed market so-

lutions for hours with relaxations. The $N-1$ violations are compared to the non-relaxed case for the same hours. As the price increases, the relaxed solutions will have less relaxations and thus fewer hours are compared when testing for $N-1$ violations. Also, from Table 5.5, it can be seen that these relaxed solutions still have a greater number of potential $N-1$ violations than the non-relaxed case. Nevertheless, all initial market solutions, including the non-relaxed market solution, must be corrected such that the dispatch solutions are $N-1$ secure.

Table 5.3. Reserve Relaxations Distinguished by Penalty Scheme and Reserve Type (MW).

Case	Reserve Type	Price 1	Price 2	Price 3	Price 4
Fixed-price	Spin	6034	104	28	0
	Non-spin	7820	877	244	78
Staircase-price	Spin	100	38	30	None
	Non-spin	131	66	58	None

Table 5.4. Total System Cost Summed Over Days with Relaxations (\$k) for Initial Market Solutions for Relaxed and Non-Relaxed Cases and Time Period with Relaxations for Relaxed Cases (days).

Case	Price 1	Price 2	Price 3	Price 4
Total System Cost for Days with Relaxations				
Fixed-price	47,832	27,761	21,782	13,291
Non-relaxed (compare w/ fixed)	48,024	27,777	21,791	13,292
Staircase-price	34,263	17,684	17,716	N/A
Non-relaxed (compare w/ staircase)	34,321	17,710	17,729	N/A
Number of Days Relaxed				
Fixed-price	28	17	13	8
Staircase	17	11	10	None

While the total system costs are similar, the non-relaxed solution exhibits considerably less $N-1$ security violations than the fixed-priced and staircase-priced relaxed solu-

tions for days with reserve relaxations because the non-relaxed solution has acquired more reserves, whereas both relaxed solutions have acquired artificial resources through the slack variables and, thus, cannot dispatch as much reserve. Even with a small difference in total system cost, the dispatch solutions are quite different in their level of $N-1$ security, i.e., the non-relaxed case is always more secure than the relaxed cases because for hours with relaxations, the relaxed cases have less reserve to deliver.

Table 5.5. Total $N-1$ Violations for hours with Relaxations (MW).

Case	Price 1	Price 2	Price 3	Price 4
Fixed-price	24218	3233	2410	828
Non-relaxed (same hours as fixed)	4111	2999	2381	722
Staircase-price	2700	2218	906	N/A
Non-relaxed (same hours as staircase)	2478	2204	859	N/A

After utilizing Benders' decomposition algorithm to correct the market solutions, $N-1$ secure solutions for all cases (fixed-price relaxed, staircase relaxed, and non-relaxed) were obtained. Table 5.6 has the total system cost after utilizing Benders' algorithm to achieve an $N-1$ secure solution. Only days that have relaxations were included. As before, the non-relaxed case is compared separately over the same days for each relaxed case. There are two entries because days with relaxations for the fixed-priced solution are not always the same as those as the staircase-priced solution.

The difference between the total system cost from the market solutions (Table 5.4) to the $N-1$ secure solutions (Table 5.6) range from 1.75% to 3.34%. The change for the fixed-price solution going from market to $N-1$ secure was the greatest for the highest penalty prices at 3.34% and the lowest for the third penalty price set at 2.27%. Comparing the non-relaxed solution for the same days as the fixed-price relaxed solutions, the

greatest change was at 2.75% for the same days of the fourth price set and 1.75% for the first price set days. For the staircase relaxed solution, the greatest change in total system cost from the initial market solution to the $N-1$ secure solution was for the second price set and the least was for the first price set. Comparing the same days of the non-relaxed case, the greatest change in total system cost was for the same days of the second price set and the least was with the first price set.

Table 5.6. $N-1$ Secure Solutions' Total System Costs Summed Over Days with Relaxations in (\$k) and Time Period (days).

Case	Price 1	Price 2	Price 3	Price 4
Total System Cost Summed over Study Period				
Fixed-price	49,041	28,529	22,277	13,735
Non-relaxed (compare w/ fixed)	48,864	28,348	22,232	13,657
Staircase-price	35,045	18,182	18,150	N/A
Non-relaxed (compare w/ staircase)	34,928	18,071	18,084	N/A
Number of Study Period (Previously Relaxed)				
Fixed-price	28	17	13	8
Staircase	17	11	10	None

When comparing the $N-1$ secure solutions, the non-relaxed solution for the same days is on whole cheaper than both of the previously relaxed cases that are now also $N-1$ secure. This is a result of the initial market solutions of both the previously relaxed cases needing more corrections to get to the $N-1$ secure solution and conversely, the fewer changes needed for the non-relaxed solution. Small differences in the initial market solutions lead to significant differences in the final outcomes, which can be seen in the differences in total cost for $N-1$ secure solutions in Table 5.6.

5.6 Conclusions

In this chapter, the effect of reserve relaxations on system $N-1$ security was investigated based on the static reserve rules utilized in the SCUC models employed by ISOs and RTOs today. Reserve requirements in the SCUC are proxy requirements and attempt to ensure $N-1$ security, but do not guarantee it.

Reserve requirements are proxy requirements that attempt to meet $N-1$ security. Reserve relaxations allowed in the market SCUC mean that less reserve has been procured because an artificial resource was acquired instead. Therefore, market solutions with reserve relaxations can have $N-1$ violations not only due to a lack of reserves, but also the approximate nature of the reserve requirement, which is one main reason for including the practice of constraint relaxation in the market because at times these approximate requirements can cause model infeasibilities if strictly enforced. Some market operators hold the opinion that some constraints should be soft constraints instead of hard constraints (strictly enforced).

The SCUC market solution is the starting point for Benders' algorithm, which is used to arrive at $N-1$ security for all solutions. As a result, the relaxed versus non-relaxed cases will have similar solutions, but the relaxed cases are always higher because of the need for more corrections. Therefore, a difference in the number of $N-1$ violations for both relaxed and non-relaxed cases still exists.

When testing for $N-1$ violations, the relaxed solutions had more violations than the non-relaxed solutions, which had a greater amount of reserves than relaxed solutions. It should be noted that the non-relaxed solution must also be corrected because of $N-1$ violations. In the end, the non-relaxed $N-1$ secure solution is cheaper than the $N-1$ secure

solutions that were previously relaxed because the relaxed solutions had more violations to correct. However, this difference is not markedly significant, which reinforces one of the main motivations behind including constraint relaxations in market models, e.g., that strictly enforcing approximate constraints such as reserve requirements that cannot guarantee $N-1$ reliability is counterproductive. One may reason that these types of approximate constraints should instead be modeled as soft constraints. Note that due to the relaxations, the relaxed cases will typically need more corrections and more adjustments to arrive at the $N-1$ secure solution for relaxed cases than non-relaxed cases. Nevertheless, the non-relaxed case must be adjusted as well. Retaining the present configuration of the market models means that current relaxation practices are justifiable, which is especially true for reserve requirements. Since a post-processing phase must still be performed, being overly strict with the reserve requirement is not justifiable. Thus, allowing the reserve requirement constraint to sometimes be relaxed for a worthy reason such as price control is a rational and judicious use of resources.

6. OUT-OF-MARKET CORRECTIONS

6.1 Introduction

The day-ahead scheduling process is generally very complex. In the USA, ISOs start by solving a SCUC market model. The day-ahead scheduling procedure can involve a variety of additional steps as well, including a RUC model [11], a scheduling run and a pricing run [9], as well other stages that adjust the market solution in order to get the final day-ahead schedule. These additional changes that happen outside the market model are referred to as out-of-market corrections (OMCs). There are additional industry terms used to refer to specific actions taken by the operator; such terms vary and include uneconomic adjustments [1], manual dispatches [12], security corrections [13], exceptional dispatches [14], and out of merit energy/capacity [20]. While this work focuses on market environments, the actual practice of implementing such adjustments is used by any operator that solves a SCUC with approximations.

Currently, such market models are deterministic, i.e., they are not stochastic programs. Even with a push towards stochastic programming, [17], day-ahead market models will continue to have approximations due to the complexity of managing such an intricate engineered system. Furthermore, there is the ongoing debate as to how much complexity is desired within market models [18]. Such debates weigh transparency, which is valued by market participants, against the efficiency of the proposed market solution as well as the accuracy of the market prices. As such, even with advances in algorithmic performance, hardware, and parallel computing, market models will continue to include such approximations, resulting in continued use of OMC procedures.

OMCs are needed due to a variety of approximations. For instance, nomograms (hyperplanes) are commonly used to ensure simultaneous operating limits are maintained. Inaccurate nomograms will require the solution to be corrected by the operator. Proxy line flow constraints may also be generated to ensure system stability, e.g., lines may be stability constrained instead of thermally constrained. Ideally, unit commitment would properly account for an ACOPF, optimize across all resources including generation and their non-convexities (e.g., ramp rates that are dependent on the dispatch level), transmission (e.g., transformer tap settings, flexible ac transmission systems devices, phase shifters, transmission switching), flexible demand, storage, and include critical uncertainties (intermittent renewables, demand, contingencies). Instead, unit commitment is currently a deterministic mixed integer linear program.

One main setback is the cost of the OMC actions. The CAISO and ERCOT spent roughly \$80 million in 2006 on OMCs [62]-[63]. In [1]-[4] and [9], CAISO, SPP, and ERCOT outline their market structures and procedures for day-ahead and real-time market settlements. In [1] and [9], CAISO states that they resort to OMC procedures in order to get feasible solutions when market based bids are insufficient. CAISO states their objective is to achieve outcomes consistent with good operational practices, which support reliable operations and prevent “unreasonable” price outcomes. The OMC procedures for SPP and ERCOT are stated in [2] and [3], respectively. The primary explanation given for the need for OMCs for these regional transmission organizations is that economic bids alone are insufficient to provide a proper solution. While this explanation is given to market participants, the true cause is market model approximations.

This work extends [35] to further examine the implications of OMCs. First, common approximations used within dispatch models and the reason these approximations are necessary are described. In Section 6.2, detailed examples of industry practices are provided for these practices that have yet to be fully analyzed in terms of their potential implications associated with market efficiency, market settlements, market bidding behavior, as well as the impact on both the day-ahead and real-time markets. Section 6.3 is a discussion and replication of a typical day-ahead scheduling process. Section 6.4 presents three algorithms, each of which modifies the market solution in order to obtain an $N-1$ reliable solution; one is designed to replicate an existing industry practice. While the presented algorithms are not guaranteed to work for every test case, they were effective for the test case studied. With these algorithms, an attempt is made to inform market stakeholders about OMCs in the day-ahead process and their implications on settlements. Section 6.5 provides results for the OMC algorithms and compares them to stochastic unit commitment results. Section 6.6 concludes this chapter.

6.2 Industry Practices

6.2.1 AC Feasibility

OMCs are almost always required. Existing SCUC market models incorporate a linear approximation of the AC optimal power flow (ACOPF), which leads to the most common need for an OMC to obtain an AC feasible solution. For instance, if there is inadequate reactive power supply in an area, an additional generator may be turned on. If there is a line overload, the operator may examine the power transfer distribution factors (PTDFs) associated to that line and then choose a set of generators to be re-dispatched.

These two actions would be classified as out-of-merit capacity and out-of-merit energy by ERCOT [20]. This commonly adopted process of using PTDFs to identify sets of generators to be re-dispatched is replicated in Section 6.4 by what is referred to as the PTDF heuristic.

6.2.2 Representation of the Network Model

OMCs may also be needed because market models approximate the network model, i.e., only select transmission lines are monitored. The ISO-NE solves SCUC without a full DCOPF formulation. ISO-NE uses approximate interface limits to estimate transfer capabilities on key paths and later performs a check on the base case power flow and selects post-contingency cases, i.e., they conduct contingency analysis. Violations are reported by contingency analysis and, time permitting, the operator may rerun the market SCUC with added constraints to correct violations. While this process can be repeated until an optimal $N-1$ solution is determined, the computational complexities inhibit solving such a procedure. Therefore, the market operator resorts to an OMC procedure to obtain a valid solution.

6.2.3 Reserve Requirements

OMCs may also be needed because proxy reserve requirement policies do not guarantee $N-1$ reliability. Even when the quantity of available reserve exceeds the largest contingency, it must be deliverable in the post-contingency state without causing post-contingency voltage violations or transmission overloads. The only way to obtain the optimal $N-1$ UC solution is to explicitly represent the post-contingency states. When such

recourse states are represented, the problem becomes a two-state stochastic program with recourse, which is extremely difficult to solve with existing technology. Many ISOs today incorporate reserve zones, which are regional reserve policies that are meant to ensure that reserves are dispersed across the system [55], [64]. While such policies improve the procurement of reserve, OMCs may still be required. Generators that are unable to deliver their reserves may be disqualified by the operator who then chooses other units to provide the needed reserve. This process is referred to as *reserve disqualification* and *reserve downflags* at MISO and ISO-NE, respectively [55]. Since operator discretion and knowledge dictate the solution quality, these procedures can be costly. These procedures also bias locational marginal prices (LMPs).

6.2.4 CAISO's Integrated Forward Market

CAISO's day-ahead market, otherwise known as the Integrated Forward Market (IFM), is separated into two stages. The first stage, i.e., the "*scheduling run*," determines the generator dispatches, which CAISO calls awards. Subsequently, CAISO performs a "*pricing run*" with the results from the scheduling run; in the pricing run, only small epsilons away from the dispatches from the scheduling run are allowed. LMPs are then determined from the pricing run.

In both stages, CAISO implements constraint relaxation procedures by allowing constraints to be violated for a set penalty, i.e., price, which is the same as placing a limit on the shadow price (dual variable) of the constraint. For example, in CAISO's scheduling run, a line's power flow may exceed its maximum thermal limit for a penalty price of \$5,000/MWh [9]. In the scheduling run, penalty prices are set much higher than in the

pricing run because CAISO seeks to find dispatch solutions with limited relaxations (violations). In the pricing run, settlements are determined and, thus, the penalty prices are much lower in order to limit excessively high prices for the resulting market solution [9]. Other ISOs also implement similar constraint relaxation practices [65]. The proposed market solution with constraint relaxations may not meet required operating standards and, therefore, may require OMC actions.

CAISO also implements a RUC after performing its scheduling and pricing runs in the IFM; the RUC ensures sufficient capacity is committed at the day-ahead time stage. The RUC procures additional capacity when the load serving entities (LSEs) purchase demand in the IFM that is less than CAISO's own demand forecast. Furthermore, CAISO removes all offers by virtual bidders in the RUC since their supply or demand is artificial and their bids are only meant to obtain market convergence. The RUC process can be seen as a formal and optimized OMC procedure. Just as OMC actions affect the market solutions in both the day-ahead and real-time stages, RUC procedures also affect market outcomes [30]. By having the RUC separate from the IFM, inefficiencies and price distortions occur. Recently, CAISO has considered merging their RUC with their IFM, [31].

6.3 Problem Formulation

The approach starts by solving a day-ahead SCUC and subsequently testing for reliability by performing $N-1$ contingency analysis in order to satisfy NERC standards. When contingency analysis finds a violation, the market-based SCUC solution is not reliable and OMC actions are needed to obtain a reliable solution; note that decomposition

techniques for stochastic programs could be used, but in this work the focus is on the role of OMC actions to obtain $N-1$ reliable solutions. After an OMC action is identified, a re-dispatch model (a SCED) is solved as a part of the overall OMC procedure. The new schedule is again checked for $N-1$ feasibility and, if it is not reliable, the process repeats. This day-ahead scheduling procedure with OMCs can be viewed in Figure 6.1. For this work, it is assumed that the SCUC model is solved at most once. There are additional variations as to how market operators may handle these situations, e.g., some of these violations may be handled by re-solving SCUC, in a RUC, or in the real-time market instead. For instance, many MMS contain a sub-routine to check the SCUC solution against a limited number of contingencies [16]; this creates an iterative process by which the SCUC solution becomes more reliable. While such sub-routines exist, based on time limitations and the limited number of contingencies that are monitored within the MMS, the market SCUC solution is still not guaranteed to be reliable. Note that there are LMPs reported at different stages in Figure 6.1 that are used in the results section to analyze the impact of OMCs.

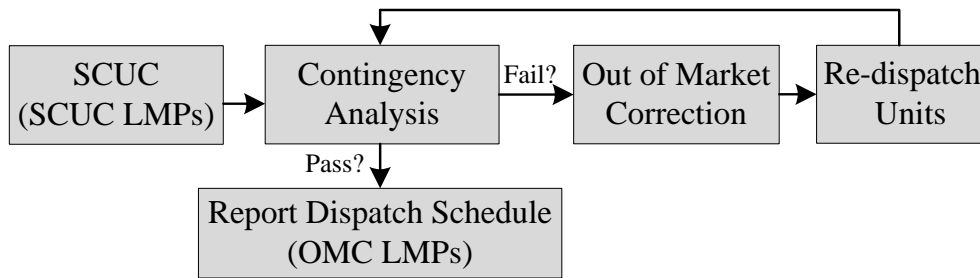


Figure 6.1. Day-Ahead Scheduling Process with OMCs.

6.3.1 Day-Ahead Security Constrained Unit Commitment

The day-ahead SCUC market model is a traditional multi-period unit commitment model with a DCOPF formulation, similar to [35]. This SCUC model, (6.1)-(6.20), accounts for spinning and non-spinning reserve requirements, which is similar to that in [22].

$$\text{Min: } \sum_t \sum_g c_g P_{gt} + c_g^{NL} u_{gt} + c_g^{SU} v_{gt} + c_g^{SD} w_{gt} \quad (6.1)$$

$$P_{gt} \geq P_g^{min} u_{gt} \quad \forall g, t \quad (6.2)$$

$$P_{gt} + r_{gt}^s \leq P_g^{max} u_{gt} \quad \forall g, t \quad (6.3)$$

$$\sum_{s=t-UT_g-1}^t v_{gs} \leq u_{gt} \quad \forall g, t \quad (6.4)$$

$$\sum_{s=t-DT_g-1}^t w_{gs} \leq 1 - u_{gt} \quad \forall g, t \quad (6.5)$$

$$v_{gt} - w_{gt} = u_{gt} - u_{g,t-1} \quad \forall g, t \quad (6.6)$$

$$P_{kt} - B_k(\theta_{nt} - \theta_{mt}) = 0 \quad \forall k, t \quad (6.7)$$

$$-P_k^{max} \leq P_{kt} \leq P_k^{max} \quad \forall k, t \quad (6.8)$$

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_g = d_{nt} \quad \forall n, t \quad (6.9)$$

$$P_{gt} - P_{g,t-1} \leq R_g^{HR} u_{g,t-1} + P_g^{max} v_{gt} \quad \forall g, t \quad (6.10)$$

$$P_{g,t-1} - P_{gt} \leq R_g^{HR} u_{gt} + P_g^{max} w_{gt} \quad \forall g, t \quad (6.11)$$

$$r_t^{max} \leq \sum_g (r_{gt}^s + r_{gt}^{ns}) \quad \forall t \quad (6.12)$$

$$r_t^{max} \geq \sum_n 0.07 d_n \quad \forall t \quad (6.13)$$

$$r_t^{max} \geq P_{gt} + r_{gt}^s \quad \forall g, t \quad (6.14)$$

$$r_{gt}^s \geq 0.5 r_t^{max} \quad \forall g, t \quad (6.15)$$

$$r_{gt}^{ns} \geq P_g^{min} (1 - u_{gt}) FS_g \quad \forall g, t \quad (6.16)$$

$$r_{gt}^{ns} \leq P_g^{max}(1 - u_{gt})FS_g \quad \forall g, t \quad (6.17)$$

$$r_{gt}^{ns} \leq R_g^{10}(1 - u_{gt})FS_g \quad \forall g, t \quad (6.18)$$

$$r_{gt}^s \leq R_g^{10}u_{gt} \quad \forall g, t \quad (6.19)$$

$$u_{gt} \in \{0,1\}; 0 \leq v_{gt}, w_{gt} \leq 1 \quad \forall g, t \quad (6.20)$$

6.3.2 Contingency Analysis

The day-ahead SCUC results are fed into an $N-1$ contingency analysis tool, which, for this investigation, is a steady-state, linearized OPF tool (note that the functional form of contingency analysis varies based on the application). The transmission emergency limits are assumed to be 125% of their long-term rated values. This tool allows the transmission limits to be violated, which is accomplished by adding slack variables to the transmission line limits. The objective is to minimize violations across all transmission lines, similar to (17)-(25) in [35], except that fast-start units are allowed to provide non-spinning reserve. This contingency analysis tool, for a single generator contingency, is shown by (6.21)-(6.28) and can be easily modified to represent a transmission contingency. The decision variables in (6.21)-(6.28) represent the post-contingency actions that would be taken.

$$\text{miniize } \sum_k s_k^+ + s_k^- \quad (6.21)$$

$$\bar{u}_g N1_g (\bar{P}_g - R_g^{10}) \leq \hat{P}_g \leq \bar{u}_g N1_g (\bar{P}_g + R_g^{10}) \quad \forall g \quad (6.22)$$

$$P_g^{min} \bar{u}_g N1_g \leq \hat{P}_g \leq P_g^{max} \bar{u}_g N1_g \quad \forall g, FS_g = 0 \quad (6.23)$$

$$0 \leq \hat{P}_g \leq (1 - \bar{u}_g) N1_g P_g^{max} \quad \forall g, FS_g = 1 \quad (6.24)$$

$$P_k - B_k(\theta_n - \theta_m) = 0 \quad \forall k \quad (6.25)$$

$$-P_k^{max,c} - s_k^- \leq P_k \leq P_k^{max,c} + s_k^+ \quad \forall k \quad (6.26)$$

$$\sum_{k \in \delta^+(n)} P_k - \sum_{k \in \delta^-(n)} P_k + \sum_{g \in g(n)} \hat{P}_g = d_n \quad \forall n \quad (6.27)$$

$$s_k^+ \geq 0, \quad s_k^- \geq 0 \quad \forall k \quad (6.28)$$

6.4 Out-of-Market Correction Procedures

Starting with the reported violations from contingency analysis, two different OMC procedures were tested. The process employed by both procedures is detailed in Figure 6.2. One procedure was utilized for both ranking algorithms, the PTDF heuristic (PTDF) and greedy algorithm (Greedy), whereas the second augmented procedure was only used with the Greedy algorithm (Greedy-A). The second procedure was tested with the PTDF heuristic, but the process did not produce a feasible solution. The ranking algorithms are performed in Step 2, shown in Figure 6.2. Both procedures modify the dispatch schedule until an $N-1$ reliable solution is obtained by taking two possible corrective actions: either the desired dispatch point (DDP) [66], of previously committed units, is modified or additional units are committed. The difference between OMC procedures 1 and 2 is based on the implementation of Steps 3 and 4.

6.4.1 OMC procedure 1

The first procedure implemented for both PTDF and Greedy begins by ranking units based on those that would have the greatest impact on the current largest contingency over all time periods (Step 1 in Figure 6.2). The OMC action ranked highest (Step 2 in Figure 6.2) for the largest recorded contingency is performed (Step 3 in Figure 6.2).

If the OMC action (Step 3 in Figure 6.2) is to turn on an additional unit, then that unit is turned on during time periods of reported violations for the given contingency as well as for other periods to satisfy operational constraints, such as minimum up and down time requirements. The new unit commitment schedule is then re-dispatched to find the new DDP of all committed units to ensure a feasible dispatch.

If the OMC action (Step 3 in Figure 6.2) is to modify the DDP of a previously committed unit, the new DDP is found by solving a modified contingency analysis model, similar to (6.21)-(6.28) for time periods that have reported violations for the current largest contingency. For the unit that will have its DDP modified by the OMC action, the reserve ramp rate restrictions are ignored and the unit is allowed to be re-dispatched anywhere between its minimum and maximum capacities. The supply level reported, during the periods of violations for the unit, is taken as the new DDP. It should be noted that any unit that has its DDP changed by a prior OMC action is still eligible for its DDP to be redefined in a subsequent correction phase of a later OMC action.

After every OMC action, a new minimum cost solution is determined (Step 4 in Figure 6.2). Units that were chosen by the OMC ranking procedure to have their DDP changed are then restricted by this re-dispatch (SCED) model to be within their 10-minute ramp capability of the required post-contingency dispatch levels determined by the OMC procedure in order to ensure violations are alleviated. Units that were chosen by the market and not chosen as an OMC action are allowed to be re-dispatched in this model subject to hourly ramp rates; they are not restricted to match their initial DDP from the market solution. This process is taken to replicate the changes to the dispatch schedule that would happen in real-time due to the implemented OMC actions. Once the system is

re-dispatched after the OMC action, contingency analysis is performed again and the process repeats until all violations are alleviated.

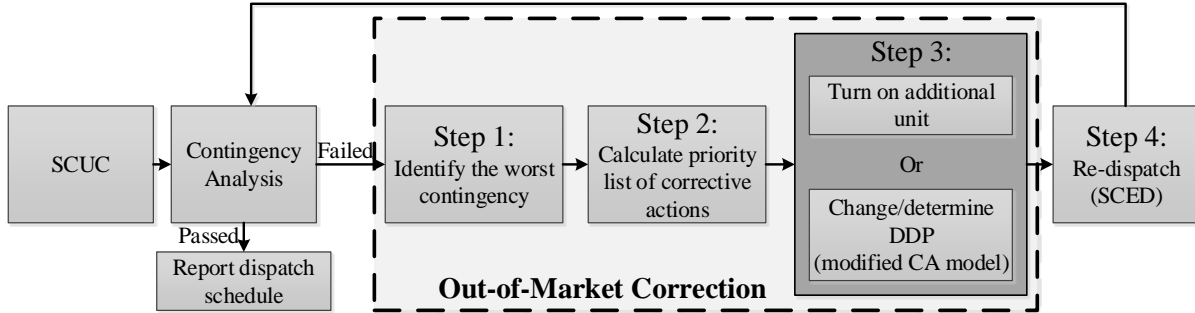


Figure 6.2. Detailed Process Employed by Both OMC Procedures.

6.4.2 OMC procedure 2

Another augmented procedure was used with the greedy algorithm (Greedy-A) only. The initial steps (Step 1 and Step 2 in Figure 6.2) are the same as *OMC procedure 1*. In Step 3, there is no difference between the two procedures when additional units are committed. The main difference was how the OMC action handled units that had their DDP modified (Step 3 and Step 4 in Figure 6.2). If the greedy algorithm determined that the most beneficial action was to modify the DDP of a specific unit, the new DDP was similarly determined as before; however, once the new DDP is chosen to alleviate the violation, it is not allowed to be changed, i.e., the new DDP for the modified units was held constant for all subsequent OMC actions (Step 3 in Figure 6.2) and re-dispatch models (Step 4 in Figure 6.2). The DDP was only allowed to move within its 10-minute ramp rate within contingency analysis. This process was repeated until a reliable solution was obtained.

6.4.3 Ranking with the PTDF Heuristic

One industry practice is to define an OMC action by examining the PTDFs for transmission lines that have overloads reported by contingency analysis. The proposed PTDF heuristic mimics this process. Generators located at buses that have large PTDFs associated with that line are positioned higher in the rank list. The specific goal is to determine which generators to turn on or modify their DDP if already committed to reduce the flow on the overloaded line as much as possible.

For situations where a contingency causes multiple lines to be overloaded, generators are ranked by accounting for their ability to reduce the flows on all of the overloaded lines. To determine this ranking, (6.29)-(6.31) are used where (6.30) is the value of turning on an additional unit and (6.31) is the value of modifying the DDP of a unit. These values are compared and the OMC action with the highest value is implemented.

For overloaded transmission lines, generator bus locations are ranked based on the sum of the PTDF values, multiplied by a parameter β_{kt}^c . When the desire is to have negative PTDFs, β_{kt}^c is set to -1. When the desire is to have positive PTDFs, β_{kt}^c is set to 1. Note that β_{kt}^c is set to 0 for lines that are not overloaded. With this heuristic, the desire is to have negative PTDFs when the flow exceeds its maximum limit and the desire is to have positive PTDFs when the flow exceeds its minimum limit. Once these $\alpha_{n(g)t}^c$ values are determined, the generators are ranked from most likely to reduce the post-contingency overload to least likely. The ranking is established by (6.30) and (6.31). The values of $\alpha_{n(g)t}^c$ are added up across all periods with violations for generator g , which is located at node n , for the periods that it is off. This value is then normalized by the num-

ber of periods it is offline. This produces γ_{cg}^{status} , which reflects the cumulative $\alpha_{n(g)t}^c$ value for each generator averaged by the number of periods the unit is offline. Likewise for γ_{cg}^{DDP} , which reflects changing the DDP of a unit, the absolute value of $\alpha_{n(g)t}^c$ is used because the DDP can be moved up or down depending on whether additional (or less) supply would create a counter-flow and thus decrease the flow across an overloaded line. γ_{cg}^{status} and γ_{cg}^{DDP} are then used to create the ranking list and the highest ranked action is the implemented OMC action.

$$\alpha_{n(g)t}^c = \sum_k PTDF_{k,n}^{REF} \beta_{kt}^c \quad \forall n, t, c \quad (6.29)$$

$$\gamma_{cg}^{status} = \frac{\sum_t \alpha_{n(g),t}^c (1 - \bar{u}_{gt})}{\sum_t (1 - \bar{u}_{gt})} \quad \forall g, c \quad (6.30)$$

$$\gamma_{cg}^{DDP} = \frac{\sum_t |\alpha_{n(g),t}^c| \bar{u}_{gt}}{\sum_t \bar{u}_{gt}} \quad \forall g, c \quad (6.31)$$

6.4.4 Ranking with the Greedy Algorithm

The greedy algorithm seeks to estimate the most beneficial change that can be made to the market solution in order to obtain a reliable solution. It is based on a sensitivity study, i.e., shadow prices are used to create a priority list of OMC actions. Shadow prices (dual variables), are used to rank the potential OMC actions based on changing the DDP or committing an additional unit and are captured in the following mathematical program (6.32)-(6.48). Equation (6.46) enforces the commitment decisions determined by the market model. The dual variable, λ_{status} , specifies the marginal impact on the objective if the right hand side of (6.46) is increased; for units that are offline ($\bar{u}_{gt} = 0$), the desire is for this dual variable to be a large negative value. Similarly, the dual variable of

(6.47), λ_{DDP} , captures the marginal value of changing a generator from its DDP. It is also preferable to have λ_{DDP} be a large negative value as well.

$$\text{minimize } \sum_k s_{kt}^+ + s_{kt}^- \quad (6.32)$$

$$\begin{aligned} \hat{P}_{gt} &\leq N1_g \bar{u}_{gt+1} (\bar{P}_{gt+1} + R_g^{HR}) \delta_{gt} + P_g^{max} (1 - \bar{u}_{gt+1}) N1_g \delta_{gt} \\ &\quad + N1_g (\bar{P}_{gt} + R_g^{10}) (1 - \delta_{gt}) \end{aligned} \quad \forall \bar{u}_{gt} = 1, g, t \quad (6.33)$$

$$\begin{aligned} \hat{P}_{gt} &\leq N1_g \bar{u}_{gt-1} (\bar{P}_{gt-1} + R_g^{HR}) \delta_{gt} + P_g^{max} (1 - \bar{u}_{gt-1}) N1_g \delta_{gt} \\ &\quad + N1_g (\bar{P}_{gt} + R_g^{10}) (1 - \delta_{gt}) \end{aligned} \quad \forall \bar{u}_{gt} = 1, g, t \quad (6.34)$$

$$\begin{aligned} \hat{P}_{gt} &\geq (N1_g \bar{u}_{gt+1} (\bar{P}_{gt+1} - R_g^{HR})) \delta_{gt} \\ &\quad + N1_g (\bar{P}_{gt} - R_g^{10}) (1 - \delta_{gt}) \end{aligned} \quad \forall \bar{u}_{gt} = 1, g, t \quad (6.35)$$

$$\begin{aligned} \hat{P}_{gt} &\geq (N1_g \bar{u}_{gt-1} (\bar{P}_{gt-1} - R_g^{HR})) \delta_{gt} \\ &\quad + N1_g (\bar{P}_{gt} - R_g^{10}) (1 - \delta_{gt}) \end{aligned} \quad \forall \bar{u}_{gt} = 1, g, t \quad (6.36)$$

$$\hat{P}_{gt} \leq \hat{u}_{gt} N1_g \bar{u}_{gt+1} (\bar{P}_{gt+1} + R_g^{HR}) + P_g^{max} \hat{u}_{gt} N1_g (1 - \bar{u}_{gt+1}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (6.37)$$

$$\hat{P}_{gt} \leq \hat{u}_{gt} N1_g \bar{u}_{gt-1} (\bar{P}_{gt-1} + R_g^{HR}) + P_g^{max} \hat{u}_{gt} N1_g (1 - \bar{u}_{gt-1}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (6.38)$$

$$\hat{P}_{gt} \geq \hat{u}_{gt} N1_g \bar{u}_{gt+1} (\bar{P}_{gt+1} + R_g^{HR}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (6.39)$$

$$\hat{P}_{gt} \geq \hat{u}_{gt} N1_g \bar{u}_{gt+1} (\bar{P}_{gt+1} + R_g^{HR}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (6.40)$$

$$P_g^{min} \hat{u}_{gt} N1_g \leq \hat{P}_{gt} \leq P_g^{max} \hat{u}_{gt} N1_g \quad \forall g, t \quad (6.41)$$

$$P_{kt} - B_k(\theta_n - \theta_m) = 0 \quad \forall k, t \quad (6.42)$$

$$-P_k^{max,c} - s_{kt}^- \leq P_{kt} \leq P_k^{max,c} + s_{kt}^+ \quad \forall k, t \quad (6.43)$$

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} \hat{P}_{gt} = d_{nt} \quad \forall n, t \quad (6.44)$$

$$s_{kt}^+, s_{kt}^- \geq 0 \quad \forall k, t \quad (6.45)$$

$$\hat{u}_{gt} = \bar{u}_{gt} N1_g \quad [\lambda_{status}] \quad \forall g, t \quad (6.46)$$

$$\delta_{gt} = 0 \quad [\lambda_{DDP}] \quad \forall \bar{u}_{gt} = 1, g, t \quad (6.47)$$

$$\delta_{gt} = 1 \quad \forall \bar{u}_{gt} = 0, g, t \quad (6.48)$$

After obtaining the dual variables associated with (6.46) and (6.47), rank lists are created for each contingency with a violation using (6.49) and (6.50). Offline units are ranked based on the dual variable, λ_{status} ; (6.49) is used to estimate the average effectiveness of turning the unit on for the hours it is off and for the hours that have violations. For the OMC actions associated with modifying DDPs, which estimates the average effectiveness of changing the DDP across all hours the unit is committed and for the hours that have violations, (6.50) is used. Both actions, represented by ρ_{cg}^{status} and ρ_{cg}^{DDP} , are ranked and the highest ranked action is implemented.

$$\rho_{cg}^{status} = \frac{\sum_t \lambda_{status}(1-\bar{u}_{gt})}{\sum_t (1-\bar{u}_{gt})} \quad \forall c, g \quad (6.49)$$

$$\rho_{cg}^{DDP} = \frac{\sum_t \lambda_{DDP} \bar{u}_{gt}}{\sum_t \bar{u}_{gt}} \quad \forall c, g \quad (6.50)$$

6.5 Results and Analysis

The IEEE-118 test case, [67], was solved by SCUC, which did not produce an $N-1$ reliable solution and was modified by the different OMC procedures (PTDF, Greedy, and Greedy-A). An extensive-form security-constrained stochastic unit commitment (ESCUC) model (a two-stage stochastic program) was solved. It provides the optimal solution to the $N-1$ UC problem since all contingencies are explicitly represented. This model is similar to [24], but transmission switching is not included. The optimal OMC action is also solved for, which is accomplished by taking the resulting market based SCUC solution and then feeding that solution into an extensive form stochastic program

for SCUC as well. This solution is represented by the ESCUC-UC result, which is based on the ESCUC model except that the ESCUC model is modified to take in the resulting market SCUC solution and not allow for any units committed by the market to be de-committed. That is, the ESCUC-UC determines the optimal $N-1$ reliable solution while requiring all units committed by the market stay committed, which provides a lower bound on all OMC actions. Settlements for the different OMC solutions (PTDF, Greedy, Greedy-A, and ESCUC-UC) were calculated using the market SCUC solution's LMPs, as well as the respective resulting OMC solution's LMPs; these two variants can be interpreted as two policy decisions: to either use LMPs that result from the market model (SCUC) or LMPs that result from the OMC actions. With the four potential OMC solutions (PTDF, Greedy, Greedy-A, and ESCUC-UC, the last representing the optimal OMC action) represented twice for the two different potential settlements rule along with the original market solution (SCUC) and the optimal $N-1$ SCUC solution (ESCUC), a stochastic program, ten different solutions are compared. These settlements are displayed in Table 6.1, and Table 6.2, and Figure 6.3.

If the settlements in the day-ahead market are based on SCUC LMPs, which is the current practice, and not the resulting LMPs after implementing OMCs, there may be a discrepancy between the day-ahead prices and the real-time market, which can be seen by the results in Figure 6.3, Table 6.1, and Table 6.2. While the posted day-ahead prices are based on the day-ahead market solution only, the actual day-ahead schedule includes the OMCs, which will be reflected in the real-time market and, hence, affect real-time LMPs. Even if limited or no trading occurs in real-time, the real-time LMPs would not be the same as the day-ahead LMPs simply due to the result of the OMCs. Such market proce-

dures may cause a market separation between the day-ahead and real-time markets, which could be exploited by market participants and virtual bidders. Such modifications to the market solution could be seen as being the same or similar to the way in which self-schedules or bilateral contracts can affect the markets. However, in this case, it is the market operator who is implementing such changes as well as relying on established settlement policies that are used to compensate the units involved with the OMC actions.

For both the Greedy and the PTDF solutions, the total system settlements were higher using the original SCUC LMPs. Settlements increased, including the total system cost, generator revenue, and load payment. On the other hand, the Greedy and PTDF solutions exhibit lower generator profits.

Table 6.1. Market Settlements for Extensive-form SCUC and SCUC (\$k for Test Day).

	ESCUC	SCUC
Total cost	1,268	1,228
Gen. revenue	3,336	1,897
Gen. profit	2,068	668
Uplift payment	374	138
Load payment	3,884	2,023
Congestion rent	548	126

When using LMPs obtained after the OMC actions, settlements are drastically different. For the Greedy solution, the settlements were higher than the SCUC. The PTDF settlements were typically lower, which is caused by the high number of OMC actions that were implemented. The PTDF heuristic ended up modifying the solution in such a way that the LMPs fell and, thus, the settlements were much lower. However, even if PTDF heuristic settlements were performed using its LMPs, the generators are still prof-

itable due to uplift payments. These settlement results can be viewed in Figure 6.3, Table 6.1, and Table 6.2. The change in the commitment schedules can be viewed in Table 6.3.

Table 6.2. Total Costs and Market Settlements of OMCs (\$k for Test Day).

	ESCUC-UC	Greedy-A	Greedy	PTDF
Total cost	1,291	1,338	1,390	1,373
Settlements using LMPs from original SCUC solution				
Gen. revenue	1,897	1,900	1,915	1,908
Gen. profit	606	562	525	534
Uplift payment	198	244	282	272
Load payment	2,023	2,023	2,023	2,023
Congestion rent	126	123	108	115
Settlements using LMPs from OMC solution				
Gen. revenue	1,983	1,957	2,234	1,246
Gen. profit	692	618	844	(127)
Uplift payment	186	258	359	504
Load payment	2,217	2,070	2,326	1,421
Congestion rent	234	114	91	175

Greedy-A settlements were not that different whether using the SCUC LMPs or its resulting LMPs, as seen in Figure 6.3, Table 6.1, and Table 6.2. The procedure used for Greedy-A made the least amount of changes to the original SCUC schedule, even compared to the ESCUC-UC solution (see Table 6.3). The Greedy-A procedure also performs better than the procedure used for Greedy and PTDF when comparing total cost to the system.

The ESCUC-UC solution, which used the market SCUC solution as a basis, obtained the optimal $N-1$ reliable OMC solution when starting from the proposed market solution (with the exception of the optimality gap). This problem explicitly models all contingencies but it does not allow any unit that is committed by the market to be de-committed. System settlements were calculated using the SCUC LMPs and its own re-

sulting LMPs. Typically, the settlements were higher when using the LMPs from the ESCUC-UC solution, which could be seen in Figure 6.3, Table 6.1, and Table 6.2.

ESCUC achieved the lowest cost solution because it simultaneously optimizes the first-stage decisions while considering the second-stage (post-contingency) corrections needed to ensure $N-1$. The settlement results for the ESCUC are drastically different compared to the other solutions. It has the highest load payment, generator revenue, profit with uplift, and congestion rent. Such results are caused by LMPs being systematically higher. The ESCUC reflects the cost of acquiring additional capacity while guaranteeing $N-1$ feasibility whereas existing SCUC models that use proxy reserve requirements do not (the ESCUC is a two-stage stochastic program whereas the SCUC is a deterministic optimization problem). While such proxy reserve requirements may provide a reliable solution, the dual variables that are used to determine LMPs are not capable of capturing the value of delivering the next MWh during the post-contingency states since such recourse states are not explicitly represented. While such a result cannot be guaranteed, the results match what is expected: that the dual variables are lower since they are incapable of reflecting the value of delivering that next MW during the potential post-contingency states.

The *missing money* debate, which argues that generators are not receiving sufficient compensation, is frequently discussed with regard to market designs. Such an argument has been used to partially justify the creation of capacity markets. In this report, the results demonstrate that if there truly is a missing money problem, it may be the result of proxy constraints that are used within market models.

The results show that there is a substantial difference between the market settlements (and prices), between the optimal $N-1$ SCUC solution (ESCUC), and the resulting solutions when using a deterministic SCUC followed by OMCs. LMPs, which are based on deterministic market SCUC models that do not explicitly represent each post-contingency state, do not capture the value of delivering the next MW during that post-contingency state. Even if generators are strategically bidding, taking into account a risk premium when determining their reserve bid, this bidding strategy would be different for the case when the auction (the market SCUC) is deterministic versus stochastic (i.e., when it would include an explicit representation of contingencies). The deterministic model has a mathematical representation of reserve requirements (e.g., zonal reserve rules) that has limited ability to distinguish the value of the reserve of one generator from another (when they are within the same zone); on the other hand, a stochastic program is capable of identifying and differentiating between reserves based on locations since the contingencies are explicitly modeled. It is thus left to future work to investigate how prices and settlements could change if market models represented reliability requirements more accurately.

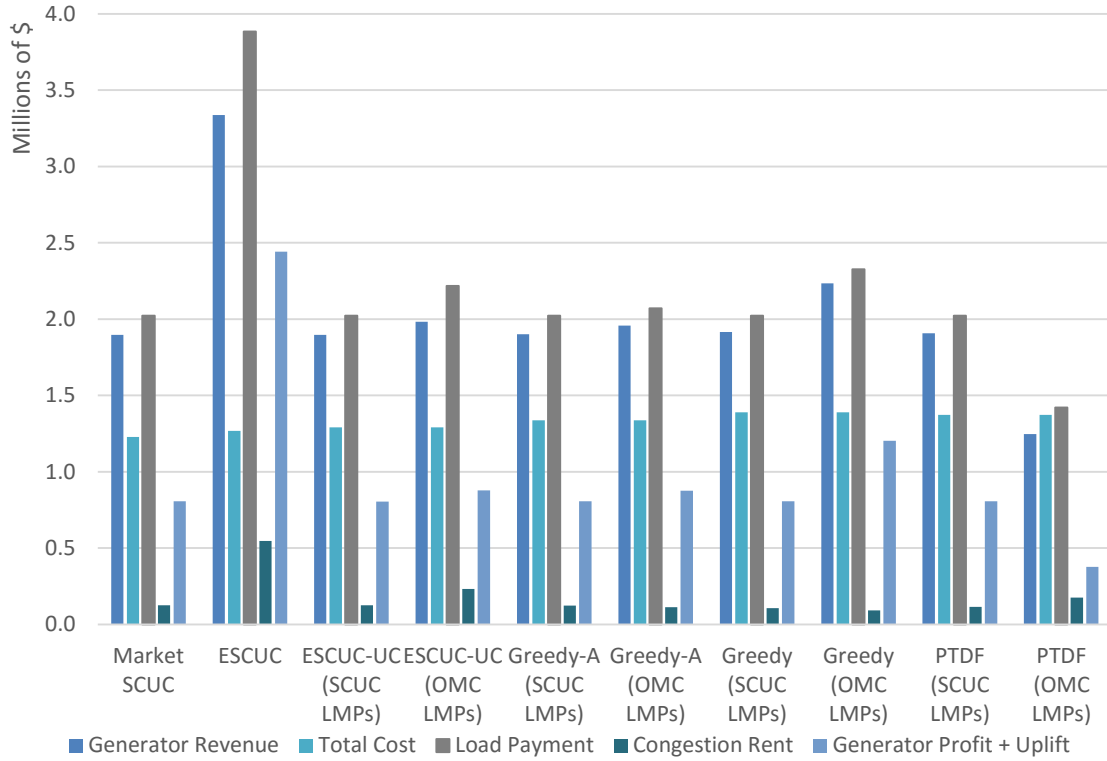


Figure 6.3. System Settlements for the Different Unit Commitment Solutions and with Different Settlement Policies by Using SCUC LMPs Versus OMC LMPs.

Solving the extensive form model without using the day-ahead SCUC solution results in the $N-1$ reliable ESCUC solution, which simultaneously optimizes first-stage dispatch decisions as well as accounts for second-stage post-contingency states to guarantee $N-1$ reliability. The result is a lowest cost $N-1$ reliable solution for the test case. System settlements differ significantly compared to the other dispatch solutions, a result of LMPs being higher overall. These higher LMPs, which reflect acquiring additional MWh at a certain location during a certain hour, also account for post-contingency states since the ESCUC solution accounts for all contingencies. For example, in this test case, a contingency on the second generator causes major $N-1$ violations. The ESCUC model accounts

for this contingency in any given hour. However, the LMPs at the bus increase tremendously, which for a few hours is over \$1000, and thus the average over the entire time period is higher than the other dispatch solutions. This result can be viewed in Figure 6.4. Similar results occur at major loaded buses.

Table 6.3. Dispatch Difference Between SCUC, Greedy, PTDF, Greedy-A, and ESCUC-UC.

Gen	Time – Hour																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1										◇	◇	◇	◇	◇	◇	◇	◇	◇	◇	◇	◇			
3								□	□	□	□	□	□	□	□	□	□	□	□	□				
6										■	■	■	■											
8									■	■	■	■	■	■	■	■								
10																	■	■	■	■	■	■	■	■
12	□	□	□	□	□	□																		
33	◇	◇	◇	◇	◇	◇	◇																	
34	◇	◇	◇	◇	◇	◇	◇	◇																
41	◇	◇	◇	◇	◇	◇	◇																	
42	□	□	□	□	□	□	□	□	■												■	□		
43	□	□	□	□	□	□	□	□													■	□		
44	□	□	□	□	□	□	□	□	■												■	□		
45	□	□	□	□	□	□	□	□													■	□		
46																		□	□					
49							■	◇																
52	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■	■							
53	□																							
54	◇	◇	◇	◇	◇	◇	◇	◇																
Original SCUC									◇	Greedy				○	PTDF				■	ESCUC-UC				□

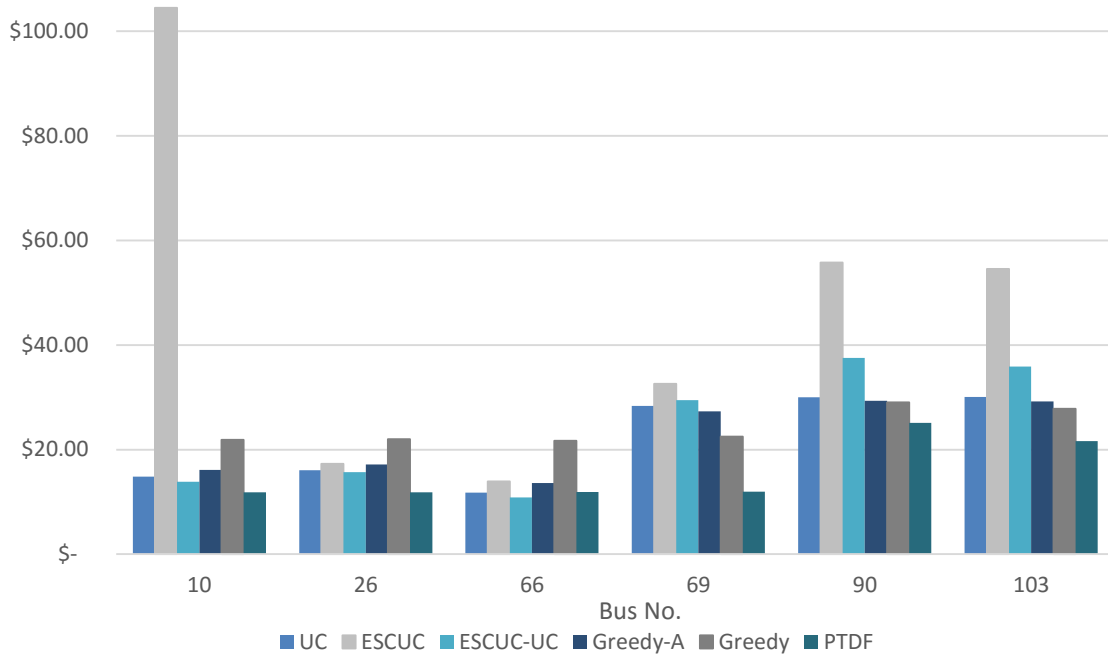


Figure 6.4. LMPs Averaged Over All Hours at Major Generator Buses.

6.6 Conclusions

Market solutions might not be feasible since the solution may not be AC feasible or the acquired reserves might not be deliverable. Such approximations require the market operator to implement OMCs. At times, such corrections can be handled by the real-time market; however, that can only happen if the operator is confident that there will be sufficient capacity. This chapter presented different OMC procedures (PTDF, Greedy, and Greedy-A) that could be used to achieve $N-1$ feasibility and discusses the corresponding market implications.

In practice, operators implement a variety of OMC actions. For example, in the day-ahead process, ISOs solve a RUC, which ensures sufficient capacity. The RUC is a formalized OMC procedure because it also modifies the market solution. For OMC pro-

cedures that are not as formalized (e.g., an operator decision to turn on additional generators to provide reactive power support), such procedures may be at the discretion of the operator. Such actions that happen outside the market may be hard to predict. On the contrary, since the OMC actions may be based on the operator's prior knowledge, similar OMC actions may frequently be chosen, which could be interpreted as a bias towards select market participants.

The results have shown that such OMC actions strongly influence commitment schedules and settlements. The results from the extensive form stochastic unit commitment model also show that the market prices from deterministic SCUC models do not capture the full value of reliability. When contingencies are explicitly represented in the optimization problem, this creates a two-stage stochastic program; the corresponding dual variables are then able to capture the costs of delivering that marginal MWh from both the normal operating state and the post-contingency states. Thus, the market implications associated with using a simplified, deterministic market model were demonstrated.

ISOs generally set market prices based on the market solution, not the resulting day-ahead schedule. This creates a natural separation between the forward (day-ahead) market and the spot (real-time) market. At this stage, it is unclear whether these procedures enable market exploitation opportunities.

Approximations will always exist for electric energy markets due to the complexity of such a complex engineered system. This work identifies the importance of these approximations with regard to their effect on market operations and settlements. Such findings add to the debate regarding desired market complexity as well as whether OMC actions should be more formalized.

7. CONCLUSIONS AND FUTURE WORK

7.1 Conclusions

The MMS used by ISOs and RTOs are mixed integer linear programs that solve unit commitment and dispatch problems. Even though the software and algorithmic performance have been improved, market models cannot fully capture all the complexities inherent in operating a complex power system. For example, various approximations within market models include a linear DCOPF rather than the more accurate ACOPF, linear ramping constraints, and proxy reserve requirements instead of explicitly modeling all contingencies. Additional complexities result from load uncertainty and, more recently, variable generation. Due to the approximations and inaccuracies that are characteristic of electric energy market models, at times the market itself leads to infeasible solutions. To guarantee feasibility, ISOs and RTOs allow select constraints to be violated or relaxed in their market models, a practice known as constraint relaxation. To incorporate a constraint relaxation within a market model, the ISO or RTO adds a slack variable to a constraint in the market model. The slack variable is then added to the objective function multiplied by a pre-determined penalty price.

In the day-ahead market model, the practices of *constraint relaxations* and *out-of-market corrections* (OMCs) were analyzed. To initiate the study of these practices, a deterministic SCUC model that accounted for generator operating constraints, reserve requirements, and a transmission network through a linearized DCOPF formulation was solved. The initial solutions from the deterministic SCUC were then modified to meet criteria known as AC and $N-1$ feasibility. Market outcomes were then analyzed based on

this process, which was detailed in Chapter 4 and Chapter 5. These criteria were met based upon operator initiated actions, referred to as OMCs. Various OMC algorithms were utilized to demonstrate the practices' effect on market outcomes as well. These OMC algorithms were also compared to an ideal solution from a stochastic program to assess how well they performed based on market outcomes and the results were given in Chapter 6.

A review of the use of constraint relaxation practices by various ISOs and RTOs was conducted. Subsequently, a proposed model with key constraint relaxations was presented. The model was solved with and without relaxations utilizing a standard IEEE test case and a 15,000 bus test case based on proprietary PJM data. Both proposed market solutions were adjusted to attain AC and $N-1$ feasibility. All solutions were compared with regard to their market outcomes. Market solutions with constraint relaxations typically needed more out-of-market corrections to reach an AC and $N-1$ feasible solution. However, this was not always the case, which was demonstrated by one of the test cases used.

Since penalty prices can greatly affect the frequency of constraint relaxations, a penalty price analysis has been included in this work. Generally, constraint relaxation practices and penalty prices are negotiated with market participants. Originally, constraint relaxation practices utilized only a single fixed-price penalty scheme, but today some ISOs and RTOs have adopted staircase penalty price curves. These two different penalty price schemes were tested with reserve requirement constraints, which are proxy requirements that attempt but do not guarantee $N-1$ feasibility. In all cases tested, the market solutions with reserve relaxations (fixed-price and staircase) had more $N-1$ security violations. Nevertheless, the non-relaxed solution had violations as well. Thus, all solu-

tions needed corrections. The relaxed solutions typically needed more corrections, which resulted in higher costs. Again, these penalty prices and schemes must be negotiated with market participants, while the process that modifies the market solution to the feasible operating solution must meet all system requirements, such as $N-1$ feasibility.

The inclusion of constraint relaxations within market models is a necessary practice for ISOs and RTOs. The industry has yet to fully understand how these practices affect market participants, therefore, the work presented investigates the impact of these constraint relaxation practices and demonstrates the possible effects by using a realistic test case that an ISO might have to solve. During this investigation, it was found that the policies of ISOs and RTOs are not readily transparent and it is recommended that they establish more candid policies regarding their constraint relaxation practices, along with steps taken to remove violations from market solutions. Additionally, it was found that the different schemes for assessing penalty prices employed by ISOs and RTOs today can influence the frequency of relaxations, which has been clearly demonstrated with reserve relaxations. Moreover, relaxing the proxy reserve requirement constraint may affect $N-1$ security since solutions with more relaxations will typically have more $N-1$ violations and thus need more corrections to attain a feasible $N-1$ secure solution. However, ISOs and RTOs are still justified in utilizing constraint relaxations in their market models to deal with these approximations that could cause infeasibilities and for price control.

OMCs (the industry has several proprietary terms for this practice) are used by all system operators including ISOs, RTOs, and vertically integrated utilities. OMCs modify the dispatch solution away from the market solution reported by the SCUC when economic bids are insufficient and produce an invalid solution that occurs due to inaccurate

assumptions and approximations in the SCUC. Even with advances in the performance of unit commitment formulations, these still require approximations to simplify the market and thus operators still need to adjust proposed solutions to guarantee a feasible solution that meets operating requirements. To demonstrate the implications these OMCs have on energy markets, a SCUC was solved and the market solution was then tested for $N-1$ reliability, which was not achieved because the contingency analysis tool reported line violations. To relieve these violations, different OMC procedures were implemented, but not all were successful. The market results were displayed for the different OMC procedures and compared using LMPs reported by the SCUC and LMPs reported by the resulting unit commitment dispatch solution after OMCs were implemented. These dispatch solutions were also compared to the market results of the ESCUC, the stochastic program whose formulation is presented in Chapter 2.6, which simultaneously solved for second stage post-contingency states while optimizing first stage unit commitment decisions, and ESCUC-UC, which utilized the least costly $N-1$ reliable solution found when starting with the market solution from the SCUC. All of these results demonstrate that any modification to the market solution from the SCUC modifies the settlements and due to ISOs typically reporting prices (LMPs) based on the SCUC forward and real-time markets, will have a natural separation in prices that could be exploited by some participants in the market. Furthermore, the lack of explicitly modelling a requirement in the market, such as $N-1$ reliability, means that the cost to attain the requirement is not truly priced into the market and must at times be handled outside the market with an out-of-market correction, which again is the cause of the price separation. Therefore, ISOs and RTOs must detail their practices not only by solving their market, but also by the process of achieving the

final feasible operating state. This work demonstrates the effects of these practices on market participants. Although ISOs and RTOS recognized that market practices such as constraint relaxations were probably affecting market outcomes, the possible effects had not been investigated and hence this work is the first attempt to document the influence of constraint relaxations and out-of-market corrections.

Finally, since market models cannot capture all uncertainties nor guarantee reliability and also contain various approximations that preclude a comprehensive representation of all operations, the use of constraint relaxations in market models is reasonable and justified. This practice, as well as the adjustment process, e.g. the use of out-of-market corrections to arrive at a feasible operating state, while justified, should be made as transparent as possible to market participants.

7.2 Future Work

The work presented in this thesis demonstrated the effects of constraint relaxation practices if relaxations are allowed in the market, but removed in the adjustment phase on constraints such as node balance, thermal line limits, and reserve relaxations from a forward market optimization model. Investigations into how constraint relaxations affect real-time operations have yet to be completed. The first issue to investigate is the effect of the duration of a constraint relaxation that appears in real-time operations – especially for line limit relaxations. The EMS of market operators will identify actual real-time relaxations. At this point the operator has authority to take immediate action or to have the real-time SCED handle this relaxation in the next round. However, according to industry advisors, there is no guarantee that the relaxation will be removed by the SCED and in-

stead the relaxation could remain. The task is to develop a heuristic method to determine penalty prices for real-time operations to update and prevent relaxations that last for long durations, i.e. as the duration of the relaxation increases then the associated penalty prices for that constraint increases as well.

Another task related to OMCs is the algorithms developed were did not account for AC feasibility. This task would involve improving the algorithms detailed in this thesis such that the algorithms modify the initial proposed forward market solution from the SCUC until an AC and $N-1$ feasible solution is obtained. As a result, the market procedures to adjust the proposed market solution to meet these criteria can become seamless in a single process.

REFERENCES

- [1] CAISO, "Parameter tuning for uneconomic adjustments in the MRTU market optimizations," *California ISO Dept. Market and Product Development*, May 6, 2008. [Online]. Available: <http://www.caiso.com/1fbf/1fbfe3a2498e0.pdf>
- [2] SPP, "Market protocols – SPP integrated market place revision 12.0," *SPP Market Design Unit*, Nov. 5, 2012. [Online]. Available: <http://www.spp.org/publications/Integrated%20Marketplace%20Protocols%2012%200.pdf>
- [3] ERCOT, "ERCOT business practice – setting shadow price caps and power balance penalties in security constrained economic dispatch," *Electric Reliability Council of Texas*, Nov. 16, 2010. [Online]. Available: http://www.ercot.com/content/meetings/natf/keydocs/2010/0930/09_ercot_busPract_shadow_price_caps_power_balance_penal.doc
- [4] X. Wang, J. Wan, and S. Gupta, "The role of system reliability in Southwest Power Pool integrated marketplace," *IEEE PES General Meeting*, Jul. 2012.
- [5] ERCOT, "ERCOT business practice – setting the shadow price caps and power balance penalties in security constrained economic dispatch." *Electric Reliability Council of Texas*, Dec. 4, 2012. [Online] Available: http://www.ercot.com/content/meetings/wms/keydocs/2011/0415/03_bus_pract_set_shadow_price_cap_wms_revised_april_15_2011.doc
- [6] N. Zottoli, "VRL Sensitivity Analysis 2008." *SPP Market Monitoring Unit*. Sept. 16, 2009. [Online]. Available: <http://www.spp.org/publications/BOD102709.pdf>
- [7] X. Ying, N. Hui, S. Qianli, and P. Nieuwesteeg, "A novel approach to transmission constraint pricing," *Power Systems Conf. and Exposition (PSCE) 2011 IEEE/PES*, pp.1-6, 20-23 March 2011.
- [8] V. Van Acker, P. Shamsollahi, C. Cathey, R. Dillon, and D. Gray, "Impact of MW dependent constraint violation penalties on market results at southwest power pool," *Transmission and Distribution Conf. and Exposition, 2012 IEEE PES*, pp.1-8, May 2012.
- [9] CAISO, "Price inconsistency market enhancements – revised straw proposal," *California ISO*, [Online]. Available: <http://www.caiso.com/Documents/RevisedStrawProposal-PriceInconsistencyMarketEnhancements.pdf>
- [10] CAISO, "Minimum Effectiveness Threshold Report," *California ISO Dept. Market Monitoring*, Apr. 2013. [Online]. Available: <http://www.caiso.com/Documents/MinimumEffectivenessThresholdReport.pdf>

- [11] A. Papalexopoulos, "Theoretical and practical considerations in implementing and using a reliability unit commitment (RUC) in restructured electricity markets," *IEEE PES General Meeting 2006*.
- [12] MISO, "ICCP Data Failure Procedure," *Midcontinent ISO*, 2012. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Procedure/RTO-AOP-007-r14.1%20ICCP%20Data%20Failure%20Procedure.pdf>.
- [13] A. J. Wood and B. F. Wollenberg. *Power Generation Operation and Control 2nd Ed.* Hoboken, NJ: Wiley, 1996.
- [14] CAISO, "2012 annual report on market issues & performance," *California ISO*, Apr. 2013. [Online]. Available: <http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf>.
- [15] ERCOT, "Report on existing and potential electric system constraints and needs," Dec. 2007. [Online]. Available: http://www.ercot.com/news/presentations/2008/35171_ERCOT_2007_Transmission_Constraints_Needs_Report.pdf
- [16] A. Castro. "Overview of MISO day-ahead markets." *Midcontinent ISO*. [Online]. Available: http://www.atcllc.com/oasis/Customer_Notices/NCM_MISO_DayAhead111507.pdf
- [17] A. Papavasiliou and S. S. Oren, "A comparative study of stochastic unit commitment and security-constrained unit commitment using high performance computing," *European Control Conf. 2013*, pp. 2507-2512, Jul. 2013
- [18] C. Vournas and T. Bakirtzis, "Oral discussions on session: markets – part II," *IREP Symposium 2013*, Aug. 2013.
- [19] E. Hildebrandt, K Collins, et al. "2012 annual report on market issues and performance." *California ISO Department of Market Monitoring*, [Online]. Available: <http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf>
- [20] ERCOT, "Report on existing and potential electric system constraints and needs," *Electric Reliability Council of Texas System Planning and Transmission Services*, Dec. 2007. [Online]. Available: http://www.ercot.com/news/presentations/2008/35171_ERCOT_2007_Transmission_Constraints_Needs_Report.pdf

- [21] O. Akinbode and K. W. Hedman, "A distribution-class locational marginal price (DLMP) index for enhanced distribution systems," *Dept. of Elect. Eng., Arizona State University*, 2013.
- [22] CAISO, "Spinning reserve and non-spinning reserve," California ISO, Jan. 2006, [Online]. Available: <http://www.caiso.com/docs/2003/09/08/2003090815135425649.pdf>
- [23] Personal Communication with Dr. Kwok Cheung, R&D Director, Alstom Grid Inc., interview conducted by Dr. K. W. Hedman, *School of Electrical, Computer, and Energy Engineering, Arizona State University*, 2013.
- [24] K. W. Hedman, M. C. Ferris, R. P. O'Neill, E. B. Fisher, and S. S. Oren, "Co-optimization of generation unit commitment and transmission switching with N-1 reliability," *IEEE Trans. Power Syst.*, vol.25, no.2, pp. 1052-1063, May 2010.
- [25] *NERC Criteria for Reliability Coordinator Actions to Operate Within IROLs*, NERC Standard IRO-009-1, Feb. 2014.
- [26] *NERC Criteria for Reliability Coordinator Actions to Operate Within IROLs*, NERC Standard IRO-008-1, Feb. 2014.
- [27] WECC, "Real-time tools guideline," *Western Electric Coordinating Council*, Jan. 2013. [Online]. Available: <https://www.wecc.biz/Reliability/Real-time%20Tools%20Guideline.pdf>.
- [28] FERC, "Recent ISO software enhancements and future software and modeling plans," *Federal Energy Regulatory Commission – Office of Energy Policy and Innovation*, 2011, [Online]. Available: <https://www.ferc.gov/industries/electric/indus-act/rto/rto-iso-soft-2011.pdf>.
- [29] M. Tahanan, W. Ackooji, A. Frangioni, and F. Lacalandra, "Large-scale unit commitment under uncertainty: a literature survey," *University of Pisa Department of Computer Science*. [Online]. Available: <http://compass2.di.unipi.it/TR/Files/TR-14-01.pdf.gz>.
- [30] G. L. LaBove, R. B. Hytowitz, and K. W. Hedman, "Market implications of reliability unit commitment formulations for day-ahead scheduling," *IEEE PES General Meeting*, pp. 1-5, Washington, DC, USA, Jul. 2014.
- [31] A. D. Papalexopoulos and P. E. Andrianesis, "Market design for the simultaneous optimization of the day-ahead market and the reliability unit commitment applications," *2013 IREP Symp.*, pp. 1-8, Crete, Greece, Aug. 2013.
- [32] ERCOT, "ERCOT nodal protocols – section 4: day-ahead operations," *Electric Reliability Council of Texas*, March 2014. [Online]. Available: http://www.ercot.com/content/mktrules/nprotocols/current/04-030114_Nodal.doc.

- [33] CAISO, "Update to CAISO draft final proposal on uneconomic adjustment policy and parameter values," *California ISO Dept. Market and Product Development*, Oct. 29, 2008, [Online]. Available: <http://www.caiso.com/Documents/RevisedDraftFinalProposalUpdate-UneconomicAdjustmentPolicyandParameterValues29-Oct-2008.pdf>.
- [34] MISO, "MISO completes largest-ever power grid integration," *Midcontinent ISO*, December 2013. [Online]. Available: <https://www.misoenergy.org/AboutUs/MediaCenter/PressReleases/Pages/MISOCOMPLETESLARGEST-EVERPOWERGRIDINTEGRATION.aspx>.
- [35] Y. Al-Abdullah, M. Abdi-Khorsand, and K. W. Hedman, "Analyzing the impacts of out-of-market corrections," *2013 IREP Symp.*, pp. 1-10, Crete, Greece, Aug. 2013.
- [36] Y. M. Al-Abdullah, M. Abdi-Khorsand, K. W. Hedman, "The role of out-of-market corrections in day-ahead scheduling," *IEEE Trans. Power Syst.*, vol. 30, no. 4, pp. 1937-1946, July 2015.
- [37] K. W. Hedman and V. Vittal, "Constraint relaxations: analyzing the impacts on system reliability, dynamics, and markets (M-29)," *Power Systems Engineering Research Center: Industry Advisor Conference Calls*, Sep. 17, 2013 and Apr. 10, 2014.
- [38] MISO, "2011 state of the market report for MISO electricity markets," *Potomac Economics – Independent Market Monitor for Midcontinent ISO*, June 2012. [Online]. Available: http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf.
- [39] MISO, "Constraint relaxation update," *Midcontinent ISO Market Subcommittee*, May 2012. [Online]. Available: <https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MS/2012/20120501/20120501%20MSC%20Item%2004a%20Constraint%20Relaxation.pdf>.
- [40] MISO, "2010 State of the market report for MISO electricity markets," *Potomac Economics – Independent Market Monitor for Midcontinent ISO*, June 2011. [Online]. Available: http://www.potomaceconomics.com/uploads/midwest_reports/2010_State_of_the_Market_Report_Final.pdf.
- [41] MISO, "Schedule 28A demand curves for transmission constraints version 1.0.0," *Midcontinent ISO*, [Online]. Available: <https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder>

- [r/MS/2013/20130806/20130806%20MSC%20Item%2004a%20Schedule%2028A%20TCDC.pdf](http://www.ercot.com/content/mktrules/nprotocols/current/06-030114_Nodal.doc).
- [42] ERCOT, “ERCOT nodal protocols – section 6: adjustment period and real-time operations,” *Electric Reliability Council of Texas*, March 2014. [Online]. Available: http://www.ercot.com/content/mktrules/nprotocols/current/06-030114_Nodal.doc.
 - [43] NYISO “Day-ahead scheduling manual,” *New York ISO*, February 2013. [Online]. Available: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/dayahd_schd_mnl.pdf.
 - [44] NYISO, “Ancillary services manual,” *New York ISO*, December 2013. [Online]. Available: http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/ancserv.pdf.
 - [45] A. George, “ISO New England – consumer liaison group meeting,” *ISO New England*, Sept. 2014. [Online]. Available: http://www.iso-ne.com/static-assets/documents/2014/09/george_clg_9_24_14.pdf.
 - [46] W. Coste, “Interregional economic study update,” *ISO New England*, Sept. 2010. [Online]. Available: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/sep212010/interrregional_eco_study.pdf.
 - [47] PJM, “Penalty factors and maximum prices,” *PJM Interconnection*, 2009. [Online]. Available: <http://www.pjm.com/~media/%20committees-groups/working-groups/spwg/20100108/20100108-item-03-penalty-factors-and-max-prices.ashx>.
 - [48] University of Washington, “Power system test case archive – RTS-96 test case,” *Dept. of Elect. Eng.*, 2007. [Online]. Available: <http://www.ee.washington.edu/research/pstca/>.
 - [49] PJM, “Reserves - scheduling, reporting, and loading,” *PJM Interconnection*, June 2013, [Online]. Available: https://pjm.adobeconnect.com/_a16103949/p5fd94w2vhd/.
 - [50] PSS/E 33.5, “Program operational manual,” Siemens, Oct. 2013.
 - [51] T. Zheng and E. Litvinov, “Ex-post pricing in the co-optimized energy and reserve market,” *IEEE Trans. Power Syst.*, vol. 21, no. 4, pp. 1528-1538, Nov. 2006.

- [52] Y.M. Al-Abdullah, A. Salloum, K.W. Hedman, and V. Vittal, "Analyzing the impacts of constraint relaxation practices in electric energy markets," *IEEE Trans. Power Syst.* vol. PP, no. 99, pp. 1-12.
- [53] A. Salloum, Y.M. Al-Abdullah, K.W. Hedman, and V. Vittal, "Impacts of constraint relaxations on power system operational security," *IEEE Power & Energy Tech. Syst.* – submitted for publication.
- [54] A. Salloum, K.W. Hedman, and V. Vittal, "Pre- and post-contingency constraint relaxations analysis and results," *Electric Power Systems Research* – submitted for publication.
- [55] J.D. Lyon, M. Zhang, and K.W. Hedman, "Locational reserve disqualification for distinct scenarios," *IEEE Transactions Power Syst.*, vol.30, no.1, pp.357-364, Jan. 2015.
- [56] MATLAB, "kmeans," *Mathworks documentation*. [Online].
http://www.mathworks.com/help/stats/kmeans.html?s_tid=gn_loc_drop.
- [57] K.W. Hedman, R.P. O'Neil, and S.S. Oren, "Analyzing valid inequalities of the generation unit commitment problem," *IEEE Power System Conf. & Exposition PES*, pp. 1-6, Seattle, WA, Mar. 2009.
- [58] D. Rajan, and S. Takriti, "Minimum up/down polytopes of the unit commitment problem with start-up costs," *IBM Research Report*, June 2005. [Online].
[http://domino.research.ibm.com/library/cyberdig.nsf/papers/CDCB02A7C809D89E8525702300502AC0/\\$File/rc23628.pdf](http://domino.research.ibm.com/library/cyberdig.nsf/papers/CDCB02A7C809D89E8525702300502AC0/$File/rc23628.pdf)
- [59] P.A. Ruiz, A. Rudkevich, M.C. Caramanis, E. Goldis, E. Ntakou, and C.R. Philbrick, "Reduced MIP formulation for transmission topology control," *50th Annual Allerton Conference on Communication, Control, and Computing (Allerton)*, 2012, pp.1073-1079, Oct. 2012.
- [60] J.D. Lyon, F. Wang; K.W. Hedman, and M. Zhang, "Market implications and pricing of dynamic reserve policies for systems with renewables," *IEEE Trans. on Power Syst.*, vol.30, no.3, pp.1593-1602, May 2015.
- [61] F. Bouffard, F. D. Galiana, and A. J. Conejo, "Market-clearing with stochastic security part II," *IEEE Trans. Power Syst.*, vol. 20, no. 4, pp. 1818–1835, Nov. 2005.
- [62] CAISO, "Intra-zonal congestion," *California ISO Dept. Market Monitoring*, Apr. 2007. [Online]. Available: <http://www.caiso.com/1bb7/1bb77b241b920.pdf>
- [63] ERCOT, "Report on existing and potential electric system constraints and needs," *Electric Reliability Council of Texas*, Dec. 2007. [Online]. Available:

- http://www.ercot.com/news/presentations/2008/35171_ERCOT_2007_Transmission_Constraints_Needs_Report.pdf
- [64] F. Wang and K. W. Hedman, "Reserve zone determination based on statistical clustering methods," *North American Power Symp. (NAPS)*, 2012, pp. 1-6, Sep. 2012.
 - [65] PSERC, "Constraint relaxations: analyzing the impacts on system reliability, dynamics, and markets (M-29)," *Power Systems Engineering Research Center – Project Summaries*, [Online]. 2014.
http://www.pserc.wisc.edu/research/project_summaries/m29.aspx.
 - [66] J. Zhao, T. Zheng, and E. Litvinov, "The do-not-exceed limit for wind generation – ISONE," *INFORMS Annual Meeting 2013*.
 - [67] University of Washington, "Power system test case archive – IEEE-118 test case," *Dept. of Elect. Eng.*, 2007. [Online]. Available:
<http://www.ee.washington.edu/research/pstca/>

APPENDIX A

CONSTRAINT RELAXATION MODEL AMPL MODEL AND RUN FILES

Model File:

```
#=====
=====
# Yousef Al-Abdullah
# M-29 -- Constraint Relaxation Project
# RTS-96 Test Case - data resolved with Ahmed Salloum
#=====
=====

#=====
=====
# Sets
#=====
=====
set GEN;
set BRANCH;
set BUS;
set TIME;
set SEG:= 1..4;
#=====
=====

#=====
=====
# Parameters - Common Parameters
#=====
=====
# Generator Parameters (use g for Generator data)
param gen_bus      {g in GEN};      # generator bus location
param min_UT       {g in GEN};      # minimum up time
param min_DT       {g in GEN};      # minimum down time
param gen_limit1   {g in GEN};
param gen_limit2   {g in GEN};
param gen_limit3   {g in GEN};
param gen_limit4   {g in GEN};
param gen_min      {g in GEN};      # generator minimum supply
param gen_max      {g in GEN};      # generator maximum supply
param Cost_SU      {g in GEN};      # generator startup cost
param Cost_SD      {g in GEN};      # generator shutdown cost
param Cost_NL      {g in GEN};      # generator no-load cost
param Cost_OP1     {g in GEN};      # generator operating cost
param Cost_OP2     {g in GEN};      # generator operating cost
param Cost_OP3     {g in GEN};      # generator operating cost
param Cost_OP4     {g in GEN};      # generator operating cost
param RampHR       {g in GEN};      # Hourly ramp rate
param Ramp10       {g in GEN};      # 10 min ramp rate
param FS           {g in GEN};      # Fast start generator unit indicator (1) for
true (0) otherwise
param HYD          {g in GEN};      # Hydro generator unit indicator (1) for true
(0) otherwise

# generator paramter to save total supply output
param vCost        {g in GEN, j in SEG};
```

```

param gLimit    {g in GEN, j in SEG};

# Branch Parameters (use k for Branch data)
param fbus      {k in BRANCH};      # branch from bus
param tbus      {k in BRANCH};      # branch to bus
param Bk        {k in BRANCH};      # branch susceptance
param CAPA      {k in BRANCH};      # branch thermal limit
param CAPE      {k in BRANCH};      # branch emergency limit

# BUS & Time Parameters (use i for Node data)
param maxLOAD   {i in BUS};          # load/demand at each bus during each period
param LoadPrnt {t in TIME};          # percentage of load each time period
param Load      {i in BUS, t in TIME}; # Load by bus and time
param NumPeriods;
let NumPeriods := 24;

# ptdf
param PTDF      {i in BUS, k in BRANCH, x in 0..120};

# Penalty Factor Parameters
param PF_line;
let PF_line := 100;

# Settlement Parameters
param LMP        {i in BUS, t in TIME};
param gen_revenue {g in GEN, t in TIME};
param gen_cost    {g in GEN, t in TIME};
param gen_profit  {g in GEN, t in TIME};
param generator_revenue_all_periods {g in GEN};
param generator_profit_all_periods  {g in GEN};
param generator_cost_all_periods    {g in GEN};
param opportunity_cost              {g in GEN, t in TIME};
param current_profit                 {g in GEN, t in TIME};
param diff_btwn_OpportunityCost_Profit {g in GEN, t in TIME};
param generator_difference_btwn_OpportunityCost_Profit {g in GEN};
param total_for_generator {g in GEN};
param take_maximum       {g in GEN};
param Uplift_payment     {g in GEN};
#=====
=====

#=====
=====
# Variables
#=====
=====
var StatusG      {g in GEN, t in TIME} binary;      # generator status
var Power_SG     {g in GEN, t in TIME, j in SEG};    # generator supply
var Supply_T     {g in GEN, t in TIME};              # total generator supply
var SpinRsv      {g in GEN, t in TIME};              # spinning reserve
var NonSpin      {g in GEN, t in TIME};              # non-spinning reserve
var TotlRsv      {t in TIME} >=0;                   # total time period reserve
var StartUp      {g in GEN, t in TIME} >= 0;        # startup genertor
var ShutDwn      {g in GEN, t in TIME} >= 0;        # shutdown generator
var PowrInj      {i in BUS, t in TIME};              # power injection for ptdf method

```

```

var slack_Lpos {k in BRANCH, t in TIME} >= 0;          # used for constraint relaxation to
INCREASE the amount of LINE FLOW in the positive direction
var slack_Lneg {k in BRANCH, t in TIME} >= 0;          # used for constraint relaxation to
INCREASE the amount of LINE FLOW in the negative direction
#=====
=====

#=====
=====
# Objective Functions
#=====
=====
# Economic Unit Commitment Objective
minimize Total_System_Cost: sum{g in GEN, t in TIME, j in SEG}(vCost[g,j]*Power_SG[g,t,j])
+ sum{g in GEN, t in TIME}(Cost_NL[g]*StatusG[g,t] + Cost_SU[g]*StartUp[g,t] +
Cost_SD[g]*ShutDwn[g,t])
+ sum{k in BRANCH, t in TIME}(PF_line*slack_Lpos[k,t] + PF_line*slack_Lneg[k,t]);
#=====
=====

#=====
=====
# Constraints
#=====
=====
# Supply Level Constraints
subject to gen_supply_minimum {g in GEN, t in TIME}: Power_SG[g,t,1] = Sta-
tusG[g,t]*gLimit[g,1];
subject to gen_supply_minimum2 {g in GEN, t in TIME, j in SEG: j >= 2}: Power_SG[g,t,j] >=
0;
subject to gen_supply_maximum {g in GEN, t in TIME, j in SEG: j >= 2}: Power_SG[g,t,j] <=
StatusG[g,t]*gLimit[g,j];
subject to total_gen_suppply {g in GEN, t in TIME}: Supply_T[g,t] = sum{j in
SEG}(Power_SG[g,t,j]);

# Synchronous condensor constraint
subject to generator_is_sync_condeser {g in GEN, t in TIME: gen_max[g] == 0}: StatusG[g,t] = 0;

# Minimum Up and Down time constraints
subject to gen_minimum_time_on {g in GEN, t in TIME}: sum{s in t - min_UT[g] + 1..t: s <=
0}(StartUp[g,s+NumPeriods]) + sum{s in t - min_UT[g] + 1..t: s > 0}(StartUp[g,s]) <= StatusG[g,t];
subject to gen_minimum_time_off {g in GEN, t in TIME}: sum{s in t - min_DT[g] + 1..t: s <=
0}(ShutDwn[g,s+NumPeriods]) + sum{s in t - min_DT[g] + 1..t: s > 0}(ShutDwn[g,s]) <= 1 - StatusG[g,t];

# Start up and shutdown constraints
subject to gen_sup_sdn {g in GEN, t in TIME: t >= 2}: StartUp[g,t] - ShutDwn[g,t] =
StatusG[g,t] - StatusG[g,t-1];
subject to gen_sup_sdn_initial {g in GEN, t in TIME: t = 1}: StartUp[g,t] - ShutDwn[g,t] = Sta-
tusG[g,t] - StatusG[g,NumPeriods];
subject to gen_startup_var {g in GEN, t in TIME}: StartUp[g,t] <= 1;
subject to gen_shutdown_var {g in GEN, t in TIME}: ShutDwn[g,t] <=
1;

# Power Balance & Net Injection Constraints

```

```

subject to node_balance_constraint      {i in BUS, t in TIME}:  -PowrInj[i,t] + sum{g in GEN:
gen_bus[g] == i}(Supply_T[g,t]) - Load[i,t] = 0;
subject to total_injection_constraint {t in TIME}:              sum{i in BUS}(PowrInj[i,t]) = 0;

# Line Flow Constraints
subject to line_maximum_constraint      {k in BRANCH,t in TIME}:      sum{i in
BUS}(PowrInj[i,t]*PTDF[i,k,0]) <= CAPA[k] + slack_Lpos[k,t];
subject to line_minimum_constraint      {k in BRANCH,t in TIME}:      sum{i in
BUS}(PowrInj[i,t]*PTDF[i,k,0]) >= -CAPA[k] - slack_Lneg[k,t];

# reserve requirment constraints
subject to total_reserve_requirement_gen_constraint {t in TIME}:      TotlRsv[t] >=
0.05*sum{g in GEN}(Supply_T[g,t]) + 0.02*sum{g in GEN: HYD[g] = 0}(Supply_T[g,t]);
subject to total_reserve_largest_gen_constraint      {g in GEN, t in TIME}:  TotlRsv[t] >=
SpinRsv[g,t] + (Supply_T[g,t]);
subject to spinning_reserve_gen_max_constraint      {g in GEN, t in TIME}:  SpinRsv[g,t] <=
gen_max[g]*StatusG[g,t] - (Supply_T[g,t]);
subject to spin_EmergencyRamp_constraint      {g in GEN, t in TIME}:  SpinRsv[g,t] <=
Ramp10[g]*StatusG[g,t];
subject to spinning_plus_Nonspinning_constraint      {t in TIME}:
TotlRsv[t] <= sum{g in GEN}(SpinRsv[g,t] + NonSpin[g,t]);
subject to mostly_Spin_constraint      {t in TIME}:
0.5*TotlRsv[t] <= sum{g in GEN}(SpinRsv[g,t]);
subject to Spin_reserve_nonzero_constraint      {g in GEN, t in TIME}:  SpinRsv[g,t] >=
0;
subject to nonspin_reserve_nonzero_constraint      {g in GEN, t in TIME}:  NonSpin[g,t] >=
0;

# Nonspinning reserve requirements
subject to non_spin_max_constraint      {g in GEN, t in TIME}:  NonSpin[g,t] <= gen_max[g]*(1-
StatusG[g,t])*FS[g];
subject to non_spin_ramp_constraint      {g in GEN, t in TIME}:  NonSpin[g,t] <= Ramp10[g]*(1-
StatusG[g,t])*FS[g];

# Ramp Up & Down Constraints
subject to gen_ramp_up_constraint      {g in GEN,t in TIME: t >= 2}:      StatusG[g,t-
1]*RampHR[g] + gen_max[g]*(1 - StatusG[g,t-1]) >= (Supply_T[g,t]) - (Supply_T[g,t-1]);
subject to gen_ramp_down_constraint      {g in GEN,t in TIME: t >= 2}:      Sta-
tusG[g,t]*RampHR[g] + gen_max[g]*(1 - StatusG[g,t]) >= (Supply_T[g,t-1]) - (Supply_T[g,t]);
subject to gen_ramp_up_constraint1      {g in GEN,t in TIME: t = 1}:      Sta-
tusG[g,NumPeriods]*RampHR[g] + gen_max[g]*(1 - StatusG[g,NumPeriods]) >= (Supply_T[g,t]) - (Sup-
ply_T[g,NumPeriods]);
subject to gen_ramp_down_constraint1      {g in GEN,t in TIME: t = 1}:      StatusG[g,t]*RampHR[g]
+ gen_max[g]*(1 - StatusG[g,t]) >= (Supply_T[g,NumPeriods]) - (Supply_T[g,t]);

# Make CR model an ED model
subject to do_not_allow_positive_relaxations      {k in BRANCH, t in TIME}:      slack_Lpos[k,t] =
0;
subject to do_not_allow_negative_relaxations      {k in BRANCH, t in TIME}:      slack_Lneg[k,t] =
0;
#=====
=====

#=====
=====

```

```

# Data Files - 118 bus test system
#=====
=====
data;

# Loads the data for the GENs and assigns the columns
# Loads the data for the GENs and assigns the columns
param: GEN: gen_bus min_UT min_DT gen_limit1 gen_limit2 gen_limit3 gen_limit4 gen_min gen_max
Cost_SU Cost_SD Cost_NL Cost_OP1 Cost_OP2 Cost_OP3 Cost_OP4 RampHR Ramp10 FS HYD:=
include gen_96.dat;
include gen_96_cost_segment.dat;
include gen_96_power_segment.dat

# Loads the data for the Lines and assigns the columns
param: BRANCH: fbus tbus Bk CAPA CAPE:=
include branch_96.dat;

# demand data
param: BUS: maxLOAD:=
include load_96.dat;

# time period data
param: TIME: LoadPrct:=
include time_96.dat;

# ptdf data
include PTDF_data96.out;
#=====
=====
Run File

#=====
=====
# Yousef Al-Abdullah
# M-29 -- Constraint Relaxation Project
# RTS-96 Test Case - data resolved with Ahmed Salloum
#=====
=====

reset;
model scucCR.mod;
option solver gurobi;      # for cplex --- option solver cplexamp;
option gurobi_options $gurobi_options 'mipgap 0.01';# for cplex --- option cplex_options "mipgap=0.1";
option gurobi_options $gurobi_options 'lpmethod 2';
option gurobi_options $gurobi_options 'outlev 1';
option gurobi_options $gurobi_options 'logfreq 5';

#=====
=====
# Calculate Load
for{i in BUS}{
    for{t in TIME}{
        let Load[i,t] := 1.1*maxLOAD[i]*LoadPrct[t]/100;

```



```

    }
}
for{g in GEN}{
    if min_UT[g] > 24 then {
        let min_UT[g] := 24;
    }
    if min_DT[g] > 24 then {
        let min_DT[g] := 24;
    }
}
}
#=====
=====
problem unit_commitment_CR:    StatusG, Power_SG, Supply_T, SpinRsv, NonSpin, TotlRsv, StartUp,
ShutDwn, PowrInj, slack_Lpos,
    slack_Lneg,
    Total_System_Cost,
    gen_supply_minimum, gen_supply_minimum2, gen_supply_maximum, total_gen_suppply, gen-
erator_is_sync_condeser, gen_minimum_time_on, gen_minimum_time_off, gen_sup_sdn,
gen_sup_sdn_initial, gen_startup_var, gen_shutdown_var, node_balance_constraint, to-
tal_injection_constraint, line_maximum_constraint, line_minimum_constraint, to-
tal_reserve_requirement_gen_constraint, total_reserve_largest_gen_constraint, spin-
ning_reserve_gen_max_constraint, spin_EmergencyRamp_constraint, spin-
ning_plus_Nonspinning_constraint, mostly_Spin_constraint, Spin_reserve_nonzero_constraint,
nonspin_reserve_nonzero_constraint, non_spin_max_constraint, non_spin_ramp_constraint,
gen_ramp_up_constraint, gen_ramp_down_constraint, gen_ramp_up_constraint1,
gen_ramp_down_constraint1;
#=====
=====
solve unit_commitment_CR;

for{i in BUS}{
    for{t in TIME}{
        let LMP[i,t] := node_balance_constraint.dual[i,t];
    }
}

for{g in GEN}{
    for{t in TIME}{
        let gen_revenue[g,t] := LMP[gen_bus[g],t]*Supply_T[g,t];
        let gen_cost[g,t] := sum{j in SEG}(Power_SG[g,t,j]*vCost[g,j]) +
Cost_NL[g]*StatusG[g,t] + Cost_SU[g]*StartUp[g,t] + Cost_SD[g]*ShutDwn[g,t];
        let gen_profit[g,t] := gen_revenue[g,t] - gen_cost[g,t];
    }
}

for{g in GEN}{
    let generator_revenue_all_periods[g] := sum{t in TIME}(gen_revenue[g,t]);
    let generator_profit_all_periods[g] := sum{t in TIME}(gen_profit[g,t]);
    let generator_cost_all_periods[g] := sum{t in TIME}(gen_cost[g,t]);
}

for{g in GEN}{
    for{t in TIME}{
        if LMP[gen_bus[g],t] <= vCost[g,1] then {

```

```

        let opportunity_cost[g,t] := 0;
    }
    else if LMP[gen_bus[g],t] > vCost[g,1] then {
        let opportunity_cost[g,t] := (LMP[gen_bus[g],t] -
vCost[g,1])*gen_max[g]*StatusG[g,t];
    }
    else if LMP[gen_bus[g],t] > vCost[g,2] then {
        let opportunity_cost[g,t] := (LMP[gen_bus[g],t] -
vCost[g,2])*gen_max[g]*StatusG[g,t];
    }
    else if LMP[gen_bus[g],t] > vCost[g,3] then {
        let opportunity_cost[g,t] := (LMP[gen_bus[g],t] -
vCost[g,3])*gen_max[g]*StatusG[g,t];
    }
    else if LMP[gen_bus[g],t] > vCost[g,4] then {
        let opportunity_cost[g,t] := (LMP[gen_bus[g],t] -
vCost[g,4])*gen_max[g]*StatusG[g,t];
    }
    else {
        let opportunity_cost[g,t] := 0;
    }
    let current_profit[g,t] := Supply_T[g,t]*LMP[gen_bus[g],t] - sum{j in
SEG}(Power_SG[g,t,j]*vCost[g,j]);
}
}
for{g in GEN}{
    for{t in TIME}{
        if opportunity_cost[g,t] - current_profit[g,t] > 0 then {
            let diff_btwn_OpportunityCost_Profit[g,t] := opportunity_cost[g,t] - cur-
rent_profit[g,t];
        }
        else {
            let diff_btwn_OpportunityCost_Profit[g,t] := 0;
        }
    }
}

for{g in GEN}{
    let generator_difference_btwn_OpportunityCost_Profit[g] := sum{t in
TIME}(diff_btwn_OpportunityCost_Profit[g,t]);
}

for{g in GEN}{
    let total_for_generator[g] := generator_difference_btwn_OpportunityCost_Profit[g] + genera-
tor_profit_all_periods[g];
}

for{g in GEN}{
    let take_maximum[g] := max(total_for_generator[g],0);
}

for{g in GEN}{
    let Uplift_payment[g] := take_maximum[g] - generator_profit_all_periods[g];
}

```

```

display StatusG > CR_genON_output.out;
display Supply_T > CR_genON_output.out;

display gen_revenue > CR_genON_output.out;
display gen_cost > CR_genON_output.out;
display gen_profit > CR_genON_output.out;
display Uplift_payment > CR_genON_output.out;

# Record Slack/ Constraint Relaxations
display slack_Lpos > CR_genON_output.out;
display slack_Lneg > CR_genON_output.out;

# Record System results
display Total_System_Cost > CR_genON_output.out;
display _total_solve_time > CR_genON_output.out;
    # saves the solve time
display LMP > CR_genON_output.out;
#=====
=====

```

APPENDIX B

CONTINGENCY ANALYSIS FROM TRANSMISSION CONTINGENCIES

$$\text{minimize } \sum_k \sum_t s_{kt}^+ + s_{kt}^- \quad \forall c \quad (\text{B.1})$$

$$\hat{P}_{gt} \geq N1_g \bar{u}_{gt} (\bar{P}_{gt} + R_g^{EM}) \quad \forall g, t \quad (\text{B.2})$$

$$\hat{P}_{gt} \leq N1_g \bar{u}_{gt} (\bar{P}_{gt} - R_g^{EM}) \quad \forall g, t \quad (\text{B.3})$$

$$\hat{P}_{gt} \leq P_g^{max} \bar{u}_{gt} \quad \forall g, t \quad (\text{B.4})$$

$$\hat{P}_{gt} \geq P_g^{min} \bar{u}_{gt} \quad \forall g, t \quad (\text{B.5})$$

$$\hat{P}_{gt} \leq P_g^{max} \quad \forall g, t, FS_g = 1 \quad (\text{B.6})$$

$$\hat{P}_{gt} \geq 0 \quad \forall g, t, FS_g = 1 \quad (\text{B.7})$$

$$N1_k (-P_{kt}^{max(EM)} - s_{kt}^-) \leq P_{kt} \leq (P_k^{max(EM)} + s_{kt}^+) N1_k \quad \forall k, t \quad (\text{B.8})$$

$$P_{kt} - N1_k B_k (\theta_{nt} - \theta_{mt}) = 0 \quad \forall k, t \quad (\text{B.9})$$

$$s_{kt}^+, s_{kt}^- \geq 0 \quad \forall k, t \quad (\text{B.10})$$

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (\text{B.11})$$

APPENDIX C

GREEDY ALGORITHM FOR TRANSMISSION CONTINGENCIES

$$\text{Minimize: } \sum_k \sum_t s_{kt}^+ + s_{kt}^- \quad \forall c \quad (\text{C.1})$$

$$\begin{aligned} \hat{P}_{gt} &\leq \bar{u}_{gt+1}(\bar{P}_{gt+1} + R_g^{HR})\delta_{gt} + P_g^{max}(1 - \bar{u}_{gt+1})\delta_{gt} + (\bar{P}_{gt} + R_g^{10})(1 - \delta_{gt}) \\ &\quad \forall \bar{u}_{gt} = 1, g, t \end{aligned} \quad (\text{C.2})$$

$$\begin{aligned} \hat{P}_{gt} &\leq \bar{u}_{gt-1}(\bar{P}_{gt-1} + R_g^{HR})\delta_{gt} + P_g^{max}(1 - \bar{u}_{gt-1})\delta_{gt} + (\bar{P}_{gt} + R_g^{10})(1 - \delta_{gt}) \\ &\quad \forall \bar{u}_{gt} = 1, g, t \end{aligned} \quad (\text{C.3})$$

$$\hat{P}_{gt} \geq (\bar{u}_{gt+1}(\bar{P}_{gt+1} - R_g^{HR}))\delta_{gt} + (\bar{P}_{gt} - R_g^{10}) \quad \forall \bar{u}_{gt} = 1, g, t \quad (\text{C.4})$$

$$\hat{P}_{gt} \geq (\bar{u}_{gt-1}(\bar{P}_{gt-1} - R_g^{HR}))\delta_{gt} + (\bar{P}_{gt} - R_g^{10})(1 - \delta_{gt}) \quad \forall \bar{u}_{gt} = 1, g, t \quad (\text{C.5})$$

$$\hat{P}_{gt} \leq \hat{u}_{gt}\bar{u}_{gt+1}(\bar{P}_{gt+1} + R_g^{HR}) + P_g^{max}\hat{u}_{gt}(1 - \bar{u}_{gt+1}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (\text{C.6})$$

$$\hat{P}_{gt} \leq \hat{u}_{gt}\bar{u}_{gt-1}(\bar{P}_{gt-1} + R_g^{HR}) + P_g^{max}\hat{u}_{gt}(1 - \bar{u}_{gt-1}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (\text{C.7})$$

$$\hat{P}_{gt} \geq \hat{u}_{gt}\bar{u}_{gt+1}(\bar{P}_{gt+1} + R_g^{HR}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (\text{C.8})$$

$$\hat{P}_{gt} \geq \hat{u}_{gt}\bar{u}_{gt+1}(\bar{P}_{gt+1} + R_g^{HR}) \quad \forall \bar{u}_{gt} = 0, g, t \quad (\text{C.9})$$

$$P_g^{min}\hat{u}_{gt} \leq \hat{P}_{gt} \leq P_g^{max}\hat{u}_{gt} \quad \forall g, t \quad (\text{C.10})$$

$$P_{kt} - N1_k B_k(\theta_n - \theta_m) = 0 \quad \forall k, t \quad (\text{C.11})$$

$$N1_k(-P_k^{max,c} - s_{kt}^-) \leq P_{kt} \leq N1_k(P_k^{max,c} + s_{kt}^+) \quad \forall k, t \quad (\text{C.12})$$

$$\sum_{k \in \delta^+(n)} P_{kt} - \sum_{k \in \delta^-(n)} P_{kt} + \sum_{g \in g(n)} P_{gt} = d_{nt} \quad \forall n, t \quad (\text{C.13})$$

$$s_{kt}^+, s_{kt}^- \geq 0 \quad \forall k, t \quad (\text{C.14})$$

$$\hat{u}_{gt} = \bar{u}_{gt} \quad [\lambda_{status}] \quad \forall g, t \quad (\text{C.15})$$

$$\delta_{gt} = 0 \quad [\lambda_{DDP}] \quad \forall \bar{u}_{gt} = 1, g, t \quad (\text{C.16})$$

$$\delta_{gt} = 1 \quad \forall \bar{u}_{gt} = 0, g, t \quad (\text{C.17})$$

APPENDIX D

CALCULATION OF UPLIFT PAYMENTS WITH OPPORTUNITY COSTS

In this section, uplift payments are calculated based on opportunity cost. When the LMP is higher than the generator operating cost and the generator is not dispatched at its maximum capacity, the generator will be paid the difference between the LMP and its operating cost for its remaining dispatch capability, which is shown in (D.1). Even after receiving the uplift payment from (D.1), generators may still not obtain enough revenue to cover their costs over the entire operating day. Therefore, a generator receiving a negative profit over the entire operating day will be compensated by the ISO such that the generator breaks even. The additional uplift payment to the generators is calculated using (D.3). The total uplift payment is the sum of these two quantities (D.4).

$$UL_g^1 = \sum_{t \in T} \left((LMP_{g(n)t} - c_g)(P_g^{max} - P_{gt}) \right) \quad \forall LMP_{g(n)t} > c_g, g, t \quad (D.1)$$

$$\Pi_g^1 = \sum_{t \in T} (LMP_{g(n)t} P_{gt} - TC_{gt}) + UL_g^1 \quad \forall g, t \quad (D.2)$$

$$UL_g^2 = \begin{cases} -\Pi_g^1 & \text{if } \Pi_g^1 < 0 \\ 0 & \text{otherwise} \end{cases} \quad \forall g, t \quad (D.3)$$

$$UL_g = UL_g^1 + UL_g^2 \quad \forall g, t \quad (D.4)$$